# ALBERTA ENERGY '84

## ENERGY RESOURCES CONSERVATION BOARD ANNUAL REVIEW OF 1983

85-1522/

# Preface

In 1983, the Energy Resources Conservation Board (ERCB) published the first of the "Alberta Energy" series. These new reports provide information regarding the energy industry in Alberta in the preceding year, and anticipated future trends. A more traditional annual report also will be issued, which will describe the ERCB's activities during the year.

The Board plans to elaborate on particular sectors of the energy industry in each issue of the "Alberta Energy" series. This issue, for example, places special emphasis on the supply of Alberta crude oil and equivalent and the contribution of Alberta supplies to meeting the North American crude oil requirements.

Your suggestions for improvement to the "Alberta Energy" series, making it more helpful to the readers, would be appreciated.

# Introduction

The Energy Resources Conservation Board (ERCB) is charged with resource development and environmental management functions in connection with oil, gas, oil sands, pipelines, coal, and hydro and electric energy. These responsibilities include ensuring that energy resources are being developed in an orderly, efficient, and safe manner, and in the overall public interest, and that the environmental standards prescribed by Alberta Environment are met.

A further ERCB responsibility is to make available to the public — including the Alberta Legislature and the energy industry — a wide variety of statistical information and forecasts of energy demand to enable readers to assess the extent, and present and future roles, of Alberta's energy resources.

Alberta Energy '84 has been prepared with these responsibilities in mind.

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# Energy Highlights

**. . . a review of Alberta's energy resources in 1983**

Activity in the energy resource industries continued to be depressed in 1983, with an overall decline from 1982 levels. However, there were some signs, such as in slightly improved prices at Crown oil and gas lease sales, that the decline may be coming to an end. Although there was an increase in drilling for oil during 1983, this was more than offset by the decline in drilling for gas.

The production of conventional crude oil in 1983 increased 1.5 per cent over that for 1982, to 56 million cubic metres (352 million barrels). Remaining established reserves of conventional crude oil increased, for the first time since 1969, to 658 million cubic metres (4.14 billion barrels). This increase resulted primarily from the upward adjustment of the reserves of old pools, but there were also significant additions due to discoveries, field enlargements, and new enhanced-recovery projects.

The production of marketable gas declined about 5.5 per cent to 63.0 billion cubic metres (2.2 trillion cubic feet) as a result of weak Canadian and export markets which declined 4 per cent and 9 per cent, respectively. Remaining established reserves of marketable natural gas declined 1.3 per cent to 1.90 trillion cubic metres (67.2 trillion cubic feet) reflecting the reduced exploration and development related to gas.

Total coal production increased in 1983 by 9 per cent to 21.6 million tonnes (23.8 million short tons). Subbituminous coal comprised 67 per cent, low- and medium-volatile bituminous coal 23 per cent, and high-volatile bituminous coal 10 per cent of the total.

Although the outlook for eastern Canadian and foreign coal markets deteriorated during the year, production began for Japanese markets at Manalta's Gregg River mine near Hinton. Construction continued at Union Oil's Obed Mountain mine near Hinton, with a view to commencing production in late 1984. Despite these activities, overall coal-related exploration and experimental activity declined sharply from earlier levels.

Alberta's petrochemical industry continued to grow in 1983 with the completion of expansions of the Esso Chemical Canada — Redwater fertilizer plant, the Sherritt Gordon Mines — Fort Saskatchewan fertilizer plant, the Husky Oil Operations — Lloydminster asphalt refinery, and the Imperial Oil — Strathcona refinery, and the new Celanese Canada — Clover Bar methanol plant. Construction was underway at the Shell Canada Resources — Scotford refinery and at the following additional plants: Shell Canada Resources — Scotford (styrene monomer), Borden Chemical Western — Edmonton (formaldehyde), Dow Chemical Canada — Fort Saskatchewan (polyethylene), NOVA — Joffre (polyethylene), Electric Furnace Products (formerly Union Carbide) — Prentiss (ethylene glycol), and the Alberta Gas Ethylene — Joffre (second ethylene). Despite this activity, a number of petrochemical projects were deferred indefinitely, a reflection of the economic recession.

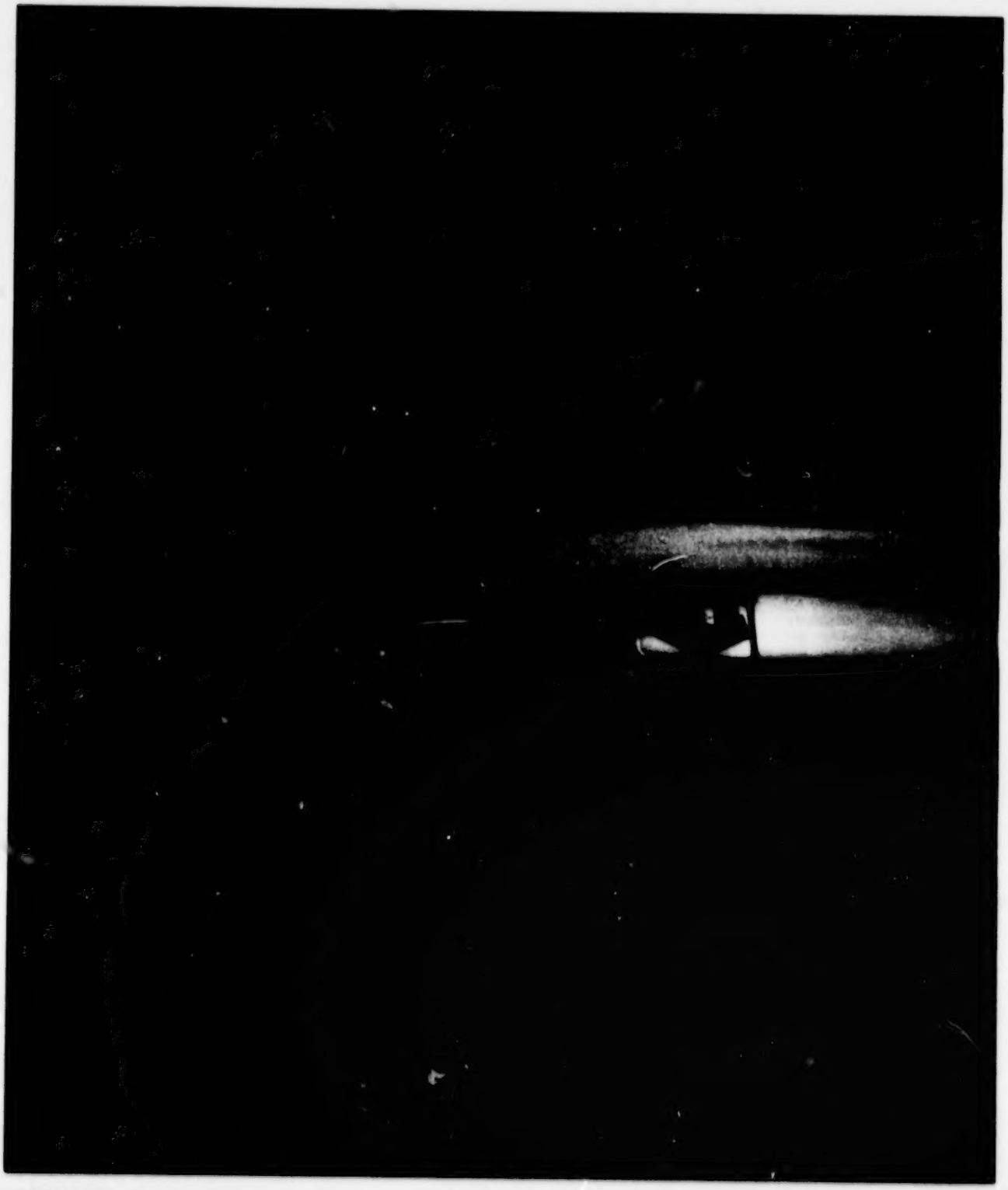
The recent growth in the production and consumption of electric energy slowed in 1983 to less than 7 per cent, as a result of slow growth or decline in various sectors of the provincial economy. The electric utilities generated 26 500 gigawatt hours of electricity in 1983, nearly all of which were consumed in the province. Their total generating capacity increased 7 per cent to 5885 megawatts with the completion of Unit No. 1 at the Keephills Generating Station near Lake Wabamun. In view of the slower provincial economic growth rate in prospect for the next few years, the completion dates of large generating facilities at Sheerness, east of Drumheller, and Genesee, southwest of Edmonton, were deferred. In addition to the electric energy generated by the electric utilities, plants at industrial sites, with a total capacity of some 655 megawatts, generated some 1700 gigawatt hours of electricity.

The first 500-kilovolt transmission lines were added to the Alberta electric system in 1983, connecting the Keephills plant to the Ellerslie substation in south Edmonton. The lines will be operated at 240 kilovolts initially and at the higher voltage when the Genesee generating plant becomes operational.

The total production in 1983 from the two commercial oil sands plants in the Athabasca deposit was 9.0 million cubic metres (56.6 million barrels) of synthetic crude oil. This was one-third more than the previous high which was achieved in 1982. Esso Resources Canada began development of the first commercial in situ bitumen recovery project at Cold Lake. Experimental activity in the oil sands and heavy oil areas remained brisk with 58 experimental projects under way.

An extensive inquiry was held during 1983 into the blowout in 1982 of a sour gas well near Lodgepole. This inquiry is discussed further in the section of this report dealing with environmental matters.

Conflicts between urban energy resource developments in the Okotoks area southwest of Calgary, in northeast Calgary, and west Edmonton were reviewed and operating conditions prescribed to control development and maintain proper safety standards. This matter is also discussed in the section on environmental matters.



*Oil Well Pump — Taber Area*

# Demand/Supply

**. . . how much energy is needed? how much do we produce? where does the energy go?**

Alberta produces more energy than it consumes. The flow of energy — as oil, gas, coal, bitumen, and hydro — to its ultimate use, either inside or outside Alberta, is shown in **Chart 1, Alberta's Energy Flows 1983.** A portion of Alberta's total primary energy production (eg: most of its natural gas) is used in a relatively unprocessed form. Other energy resources are consumed in converting a raw resource into other energy forms (eg: coal used to generate electricity).

The basic energy unit in the metric system is the "joule", which is a very small unit. Its value is about 1/1000th of a British thermal unit which is the basic energy unit of the imperial system of units. When discussing the energy production of Alberta in metric energy units, it is more convenient to speak in terms of "exajoules" ($10^{18}$ joules). An exajoule is roughly equivalent, in energy content, to 28 billion cubic metres (1 trillion cubic feet) of gas. Alberta presently consumes about two-thirds of an exajoule of gas each year. A petajoule, also used frequently, is 1/1000th of an exajoule. Other multiples of the joule which are used in this report are described under Units of Measurement at the back of the report.

In this review, Alberta's energy resource needs are divided into the categories of hydrocarbon and electric. Hydrocarbon requirements are those used for purposes other than the generation of electricity (eg: direct consumption of natural gas for heating, or the conversion of oil into gasolines, or gas into petrochemicals). These hydrocarbon requirements are further subdivided into:

(a) those needed to satisfy Alberta's requirements,
(b) those needed for conversion into non-energy products (eg: greases and petrochemical feedstocks), and
(c) those shipped out of the province in a refined form.

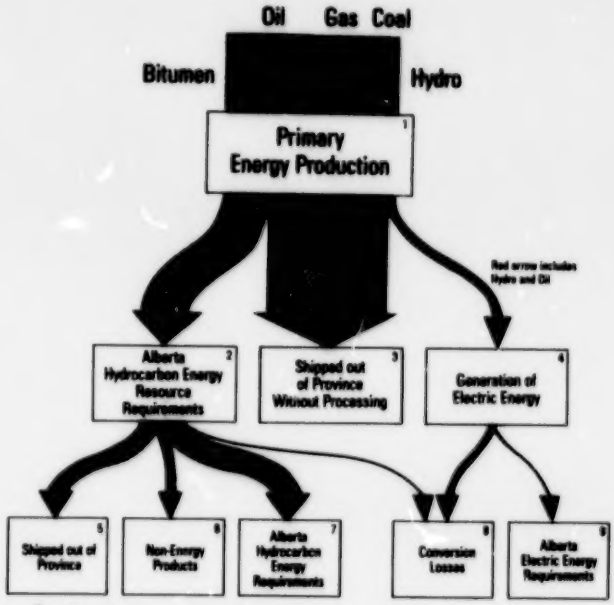
The electric energy requirements category comprises those energy resources used in the generation of electricity. These electric energy resource requirements are further subdivided into

(a) the portion delivered as electricity to markets in Alberta, and
(b) the portion consumed while making electricity (known as conversion losses).

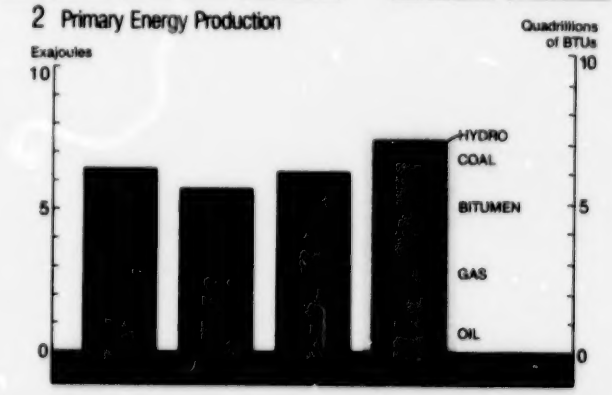
Historical and projected production rates of oil, gas, bitumen, coal, and hydro energy are shown in total in **Chart 2, Primary Energy Production,** and by individual resource in **Charts 3, Crude Oil and Equivalent, 4, Gas, 5, Bitumen, 6, Coal,** and **7, Hydroelectricity.** The sharp increase in production of hydroelectricity projected for the year 2000 (Chart 7) is based on the assumption that large hydro developments proposed at Dunvegan, on the Peace River, and at Mountain Rapids, on the Slave River, will meet approval requirements and be completed by that time.

Total hydrocarbon energy resource requirements (non-electric) for oil, gas, coal, bitumen, and natural gas liquids (NGLs — ethane, butanes, and propane) are shown in **Chart 8, Hydrocarbon Energy Resource Requirements,** with the historical and projected individual energy resource requirements shown in **Charts 9, Oil, 10, Gas, 11, Bitumen,** and **12, Coal.**

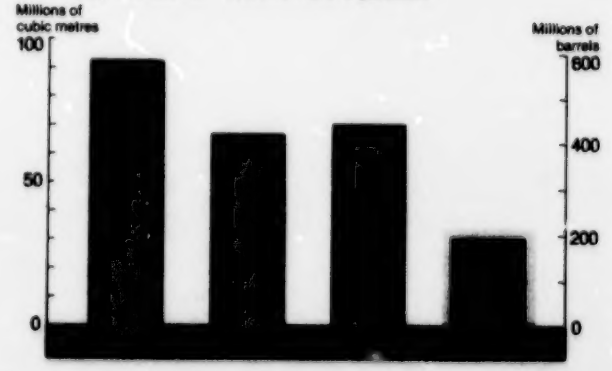
1 Alberta's Energy Flows 1983




2 Primary Energy Production




3 Primary Production - Crude Oil and Equivalent

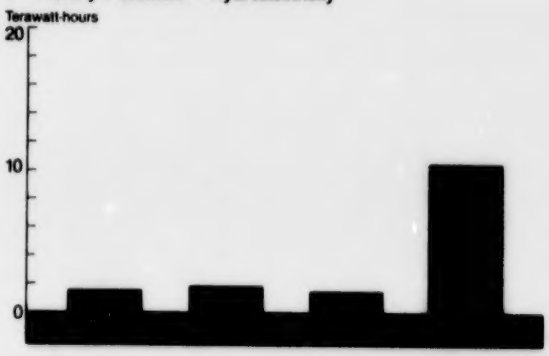


4 Primary Production - Gas

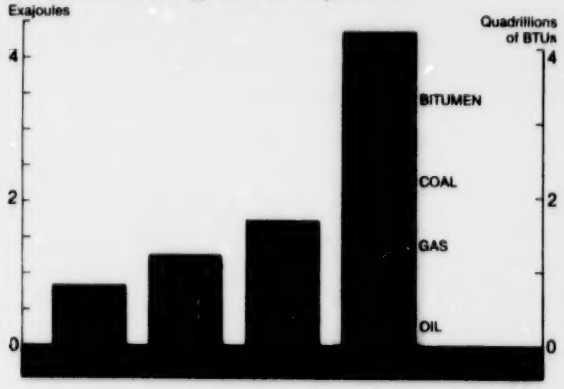
5 Primary Production - Bitumen

6 Primary Production - Coal

7 Primary Production - Hydroelectricity




8 Hydrocarbon Energy Resource Requirements




9 Alberta Hydrocarbon Requirements - Oil

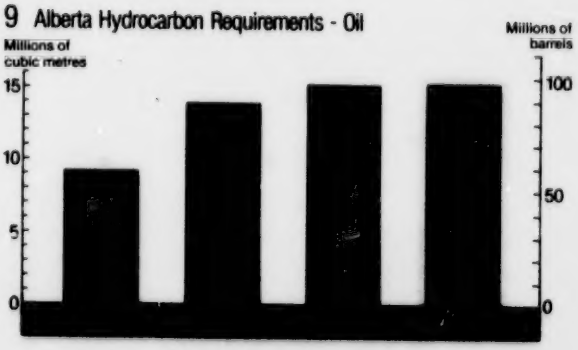
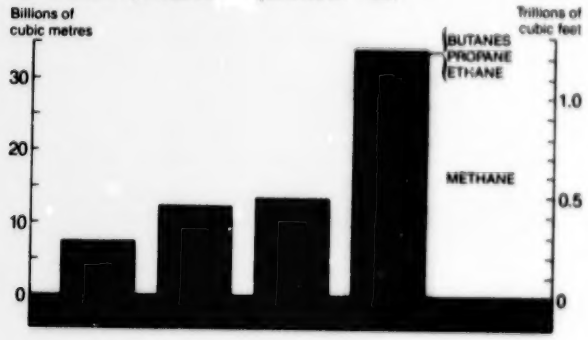


**Chart 13, Refined Products Shipped Out of Province,** shows the amounts of synthetic crude oil and refined petroleum products which are currently shipped, or projected to be shipped, out of the province. This chart should be viewed with Chart 16 (Primary Energy Shipped out of Province) when considering total oil deliveries to markets outside Alberta.

Alberta energy requirements for non-energy products (Box 6 of Chart 1) include energy requirements for products where the energy content is not the critical factor. This includes asphalt, lubricating oils, petrochemical feedstocks, and gas used in upgrading bitumen to synthetic crude oil. The historical and projected amounts required are illustrated in **Chart 14, Energy Requirements for Non-Energy Use.**

Alberta's hydrocarbon energy requirements (Box 7 of Chart 1) are subdivided into major end-use categories in **Chart 15, Alberta Hydrocarbon Energy Requirements.** They include fuel for refineries and oil sands and petrochemical plants, refined petroleum fuels used in the province, and natural gas consumed in residential, commercial, industrial, and transportation facilities as fuel. Also included is a small amount of coal used as fuel rather than for the generation of electric energy. Some hydrocarbon energy resources are consumed in converting the energy resources to more expensive fuels and products (known as conversion losses).

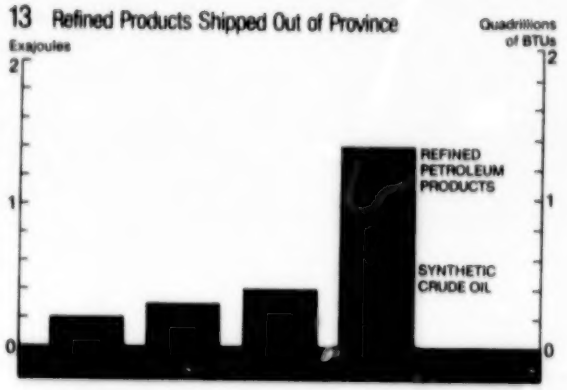
10 Alberta Hydrocarbon Requirements - Gas



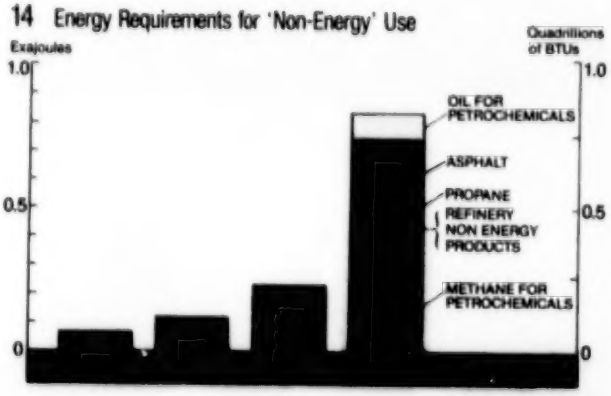

11 Alberta Hydrocarbon Requirements - Bitumen

12 Alberta Hydrocarbon Requirements - Coal

13 Refined Products Shipped Out of Province




14 Energy Requirements for 'Non-Energy' Use



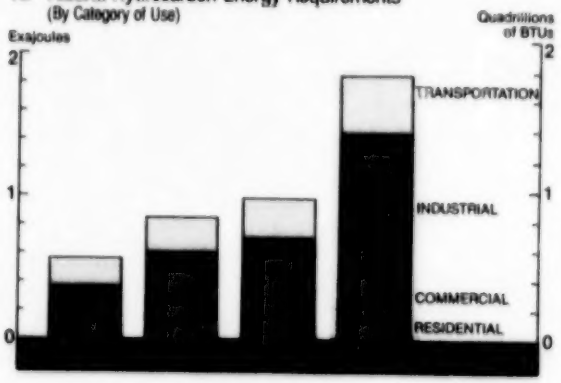
The primary energy shipped, and projected to be shipped, out of the province, without being processed, is shown in **Chart 16, Primary Energy Shipped Out of Province.** This includes oil, coal, gas, synthetic crude oil, and some bitumen. Most bitumen is processed in Alberta and part of the products are sold outside the province (see Chart 13).

Electric energy resource requirements used to generate electricity, including all coal, hydro, gas, and oil, are illustrated in **Chart 17, Electric Energy Resource Requirements.**

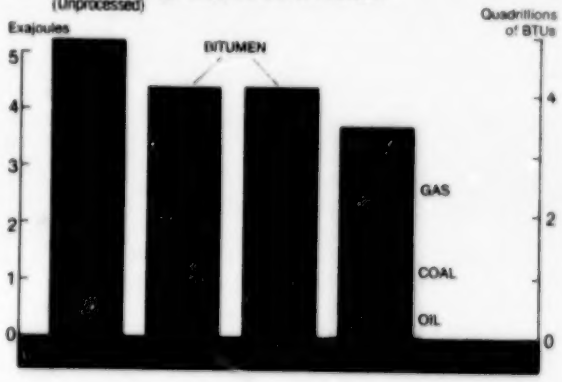
The requirements shown in **Chart 18, Alberta Electric Energy Resource Requirements,** are categorized into end-use electricity consumption (Box 9 of Chart 1) and the amount of energy consumed in conversion (Box 8 of Chart 1). The electricity exchanged with neighbouring provinces each year and that generated at industrial sites is insignificant in relation to the total generated by the utilities in the province.

Note: Statistics on energy requirements for the period 1973-1983 were derived from actual values reported to the ERCB by utilities and major consumers. The forecast requirements for the year 2000 are taken from the publication "Energy Requirements in Alberta 1982-2005", ERCB Report 82-F.

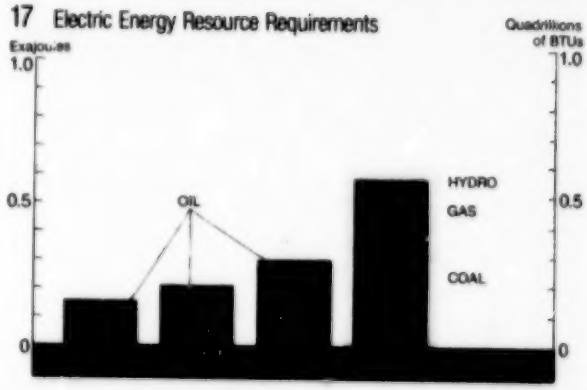
15 Alberta Hydrocarbon Energy Requirements
(By Category of Use)



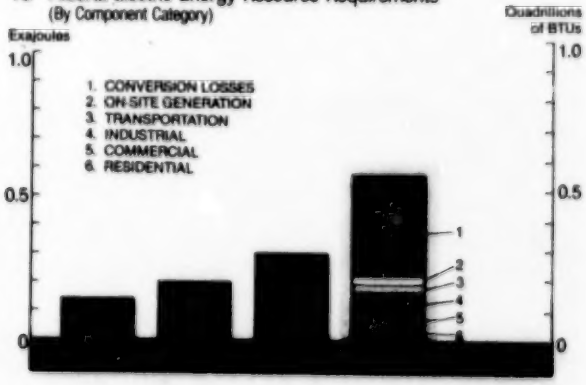

16 Primary Energy Shipped Out of Province
(Unprocessed)




17 Electric Energy Resource Requirements




18 Alberta Electric Energy Resource Requirements
(By Component Category)



# Exploration and Development

**. . . looking for and developing energy**

Exploration and development of Alberta's energy resources continued to decline in 1983 although activity related to oil increased, especially in the second half of the year.

## OIL AND GAS

### DRILLING

The total number of oil and gas wells drilled in 1983 continued its downward trend **(Chart 19, Oil and Gas Wells Drilled)** with total drilling falling to an 8-year low. There were 4367 wells drilled in 1983 representing a 15 per cent decline from 1982 and a 38 per cent decline from the 1980 peak-activity year when 8419 wells were drilled. *Exploratory* drilling declined 22 per cent from 1982 **(Chart 20, Exploratory Wells Drilled),** while *development* drilling was down 11 per cent **(Chart 21, Development Wells Drilled).** The total depth drilled annually also continued to decline from the 1980 peak year **(Chart 22, Depth Drilled).** The number of wells drilled for gas was down substantially but the number of wells drilled for oil showed a strong improvement.

The province's short-term Development Drilling Incentive System (DDIS) provided some stimulus to the mid-year drilling activity for oil. This activity was assisted by bouyant oil markets, and the granting of prices near world prices (NORP — new oil reference price) for some additional categories of oil production. Production from oil discoveries and field extensions began receiving NORP on 1 January 1981, and these prices were extended to additional new qualifying wells in old pools effective 1 July 1983. The extension of NORP to some infill wells appears to have been a major factor leading to the strong gain in drilling activity during the last half of 1983. In consequence, 2085 conventional oil wells (excluding oil sands wells) were completed in 1983, establishing a 10-year high for oil wells, and reflecting a 33 per cent increase over the 1982 level. This trend towards increased drilling activity related to oil has continued into 1984.

### PIPELINES

**Chart 23, Pipelines Licensed — Cumulative,** shows the growth in cumulative length of pipelines licensed by the ERCB for the 5-year period 1979-1983 inclusive. These statistics will be altered, beginning with ERCB's 1985 report, since jurisdiction for gas distribution lines[1] will by then be transferred from the ERCB to Alberta Utilities and Telecommunications.

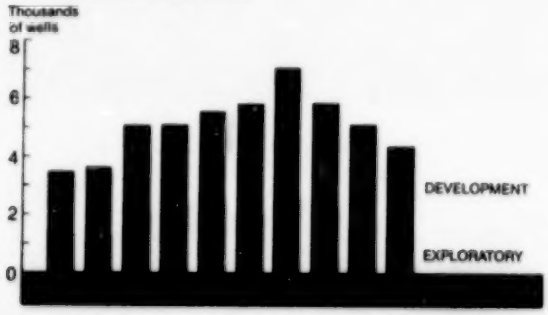
**Chart 24, Pipelines Licensed — Annual,** which compares — by type — the lengths of pipeline licensed over the same 5-year period 1979-1983, shows some interesting trends. In particular, there has been a substantial decline in the total length of oil lines licensed annually. Licensing of gas transmission lines, on the other hand, has increased at a steady rate. Distribution lines, which include most of the lines in the rural gas program, will disappear entirely from the ERCB records in the coming years as discussed above.

### GAS PLANTS

The number of gas plants operating in Alberta increased from 155 in 1973 to 485 in 1983 **(Chart 25, Gas Plants Approved and Their Capacities).** The raw gas processing capacity of these plants increased from 290 to 425 million cubic metres (10.3 to 15.1 billion cubic feet) per day in the same period.

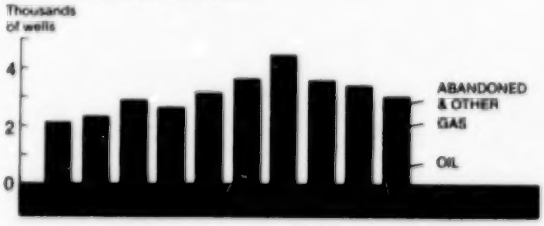
1 Gas distribution pipelines that operate at 700 kPa (100 psi) or less.

19 Oil and Gas Wells Drilled

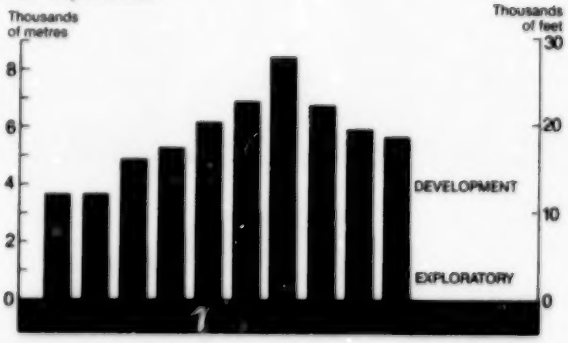


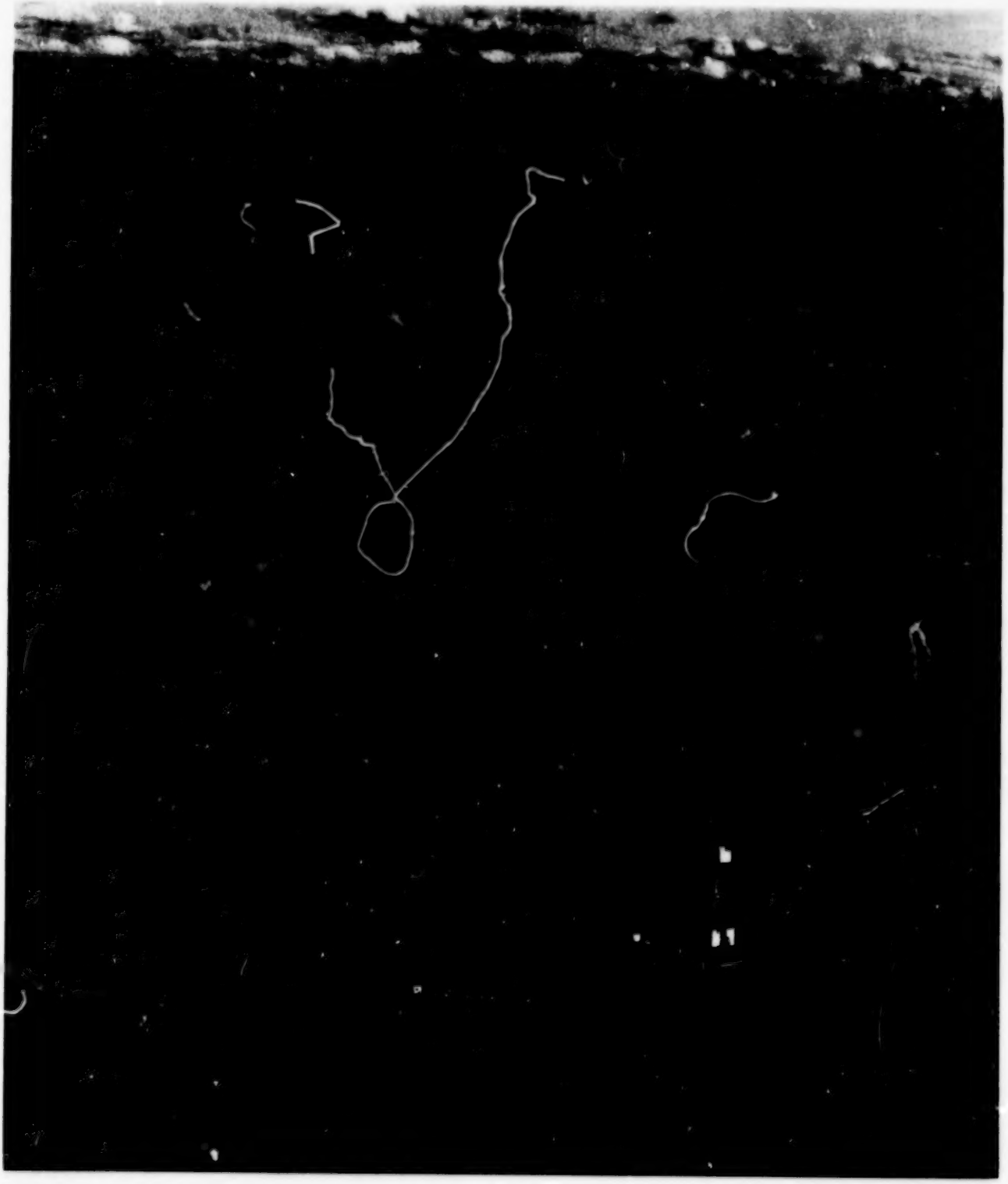

20 Exploratory Wells Drilled

21 Development Wells Drilled



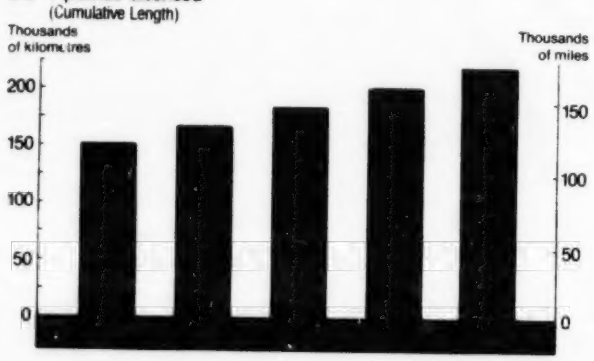

22 Depth Drilled



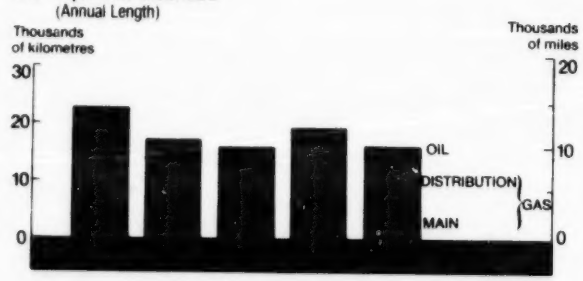


*Drilling Rig on location in the Porcupine Hills*

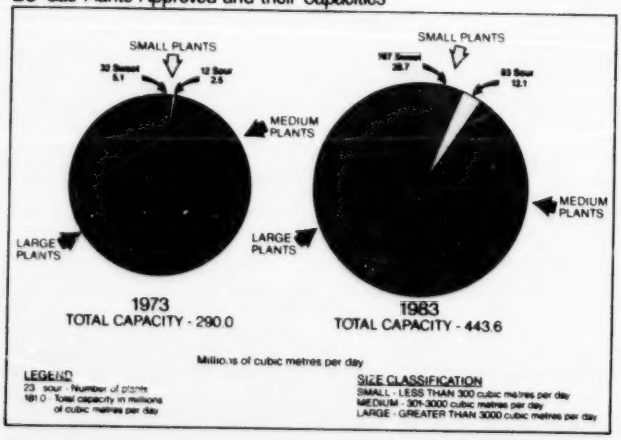
23 Pipelines Licensed
(Cumulative Length)




24 Pipelines Licensed
(Annual Length)




25 Gas Plants Approved and their Capacities




Although only 23 per cent of Alberta's remaining established gas reserves contain hydrogen sulphide (are sour), approximately 53 per cent of the gas marketed in 1983 was derived from raw sour gas. By year-end, 167 plants had been approved to process sour gas. These plants had a gross raw gas capacity of 276 million cubic metres per day and comprised some 65 per cent of the total provincial raw gas processing capacity.

Most of the gas was processed at large plants, but the trend in recent years has been toward greater use of small plants as shown in Chart 25. This trend probably is the result of improving gas prices which have made it economic to develop small, more remote gas reserves.

### INDUSTRIAL PLANTS

**Chart 26, Major Industrial Plants Operated,** shows the number of petrochemical plants, refineries, and other[2] plants operating in Alberta. Where the expansion of an existing plant required significantly more energy, that expansion has been counted as a new plant.

**Chart 27, Energy Requirements of Major Industrial Plants,** shows the growth in the annual energy requirements of major industrial plants (at their design capacities). These energy requirements are subdivided into fuel and feedstock. The chart includes data for only those industrial plants which consume more than 1 petajoule of energy annually as raw material or fuel, or 100 terajoules as raw material (equivalent to 1 billion or 100 million cubic feet of gas, respectively).

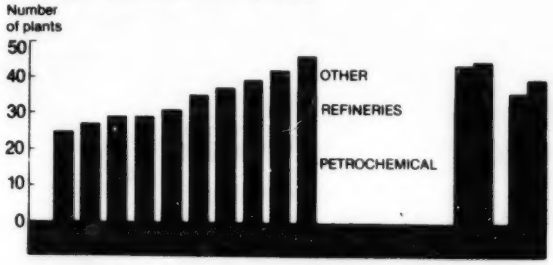
The markets for petrochemicals and other industrial commodities were weak in 1983 and the world economic recession has led to the indefinite deferment or cancellation of some Alberta projects. However, production of petrochemical products in Alberta increased in 1983 by 13 per cent on a value basis to $3.6 billion. Those Alberta industrial plants which use gas as feedstock and fuel operated at 79 per cent of capacity during the year, compared with 87 per cent in 1982.

## COAL

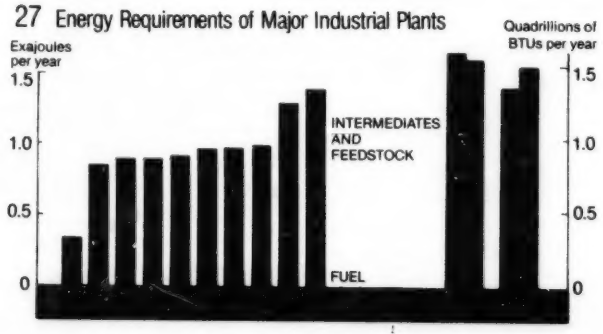
Coal exploratory drilling activity, in all three provincial coal regions, declined in 1983 to 556 holes **(Chart 28, Coal Exploration Holes Drilled).** This was less than half the level achieved in 1982. Indeed, the 1983 level of drilling was substantially lower than for any other year in the past decade, reflecting the depressed outlook for new coal markets. Construction of several commercial coal facilities continued during the year but a number of planned projects were deferred.

2 Includes two cement plants, two pulp mills, one sugar refinery, one lime plant, and one chlorine/caustic soda plant.

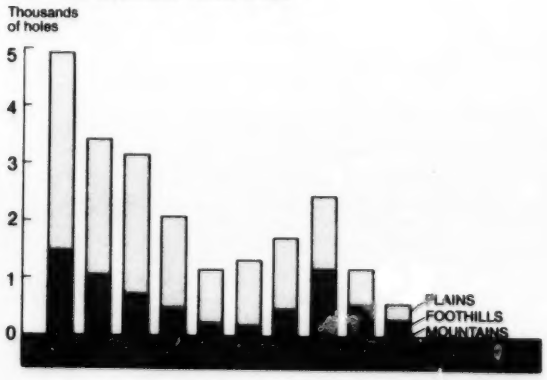
## 26 Major Industrial Plants Operated



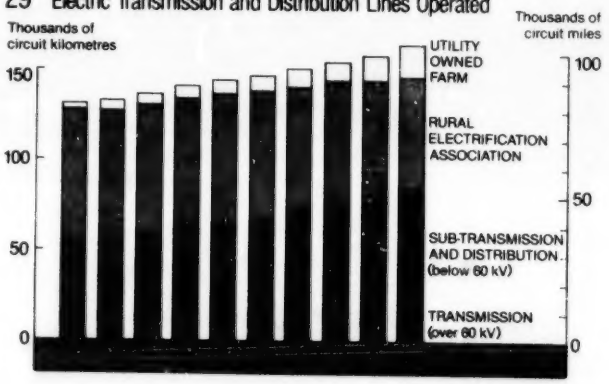

## 27 Energy Requirements of Major Industrial Plants



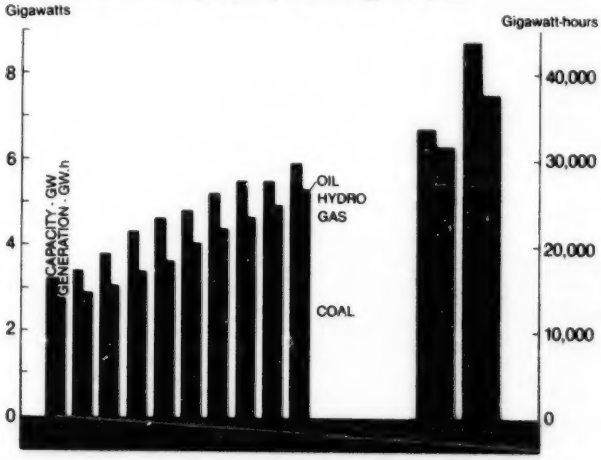

## 28 Coal Exploration Holes Drilled



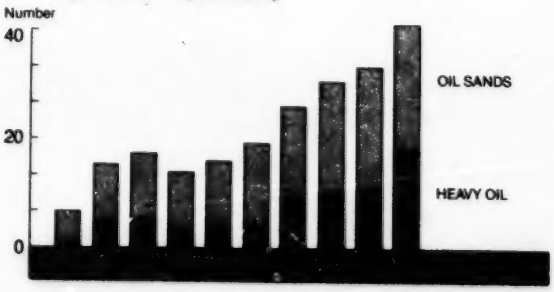

## 29 Electric Transmission and Distribution Lines Operated




## 30 Electric Generating Capacity and Energy Generated




## 31 Experimental Project Activity



## HYDRO AND ELECTRIC

**Chart 29, Electric Transmission and Distribution Lines Operated,** shows the growth in the types and total length of electric transmission and distribution lines operating in the province. There has been a gradual reduction in overall length of lines owned by Rural Electrification Associations (REAs) and a corresponding increase in utility-owned farm lines, over the past 10 years. This reflects the increasing number of REAs that are selling their facilities and service obligations to the major utilities.

**Chart 30, Electric Generating Capacity and Energy Generated,** shows the growth in electric generating capacity in the province, and energy generated. The chart shows the increasing trend in generation of electric energy from coal and the decline in generation from natural gas, resulting from the sharp increase in natural gas prices in recent years. Government policy discourages large new gas-fired generating units since gas is a less plentiful resource than coal in Alberta.

The recent Alberta economic slowdown has resulted in a reduction in the required growth in the electric generating capacity. Chart 30 indicates, that while growth is expected to continue, a smaller increase in capacity is expected to be required by 1990. The additional capacity now expected to be required by 1990 is only 56 per cent of the increase forecast in 1980, when Alberta was experiencing rapid growth.

## OIL SANDS AND HEAVY OIL

### EXPLORATION AND EXPERIMENTAL ACTIVITY

Interest and activity in oil sands, and heavy oil thermal experimental schemes, has increased steadily from 1974 to 1983 **(Chart 31, Experimental Project Activity).** Presently, thermal schemes are being developed mainly along the Cold Lake-Lloydminster trend, although interesting projects also are being pursued on a sustained basis in other areas such as at Peace River and near Fort McMurray.

Currently, there are 14 experimental projects in the Athabasca, 18 projects in the Cold Lake, and 1 project in the Peace River oil sands deposits. In the heavy oil areas, 28 experimental projects are under way. Most of the projects involve the injection of steam or generating heat underground through the combustion of injected air or oxygen.

Total annual production of crude bitumen and heavy oil from these experimental projects increased from 73 thousand cubic metres (460 thousand barrels) in 1974, to 1455 thousand cubic metres (9.2 million barrels) in 1983. The number of experimental wells increased, from 300 to 1568, during the same period.

*Brazeau Hydro Development*

*Bucket Wheel Excavator at Suncor Oil Sands Project*

# Environmental Matters

**. . . environmental impacts of energy resource developments and how they are controlled**

Energy resource developments invariably produce a number of environmental impacts, particularly on the land surface and to the atmosphere. The major land surface effects considered here are those resulting from oil and gas, oil sands, hydro and electric, and coal operations. They are produced by well and pipeline incidents, other kinds of liquid spills, by oil sands and coal excavation, by waste materials disposal, and by construction and servicing of energy resource facilities. The emissions to the atmosphere from gas processing, crude bitumen recovery and processing, and thermal electric plants are discussed as well.

## FLUID RELEASE INCIDENTS

Apart from permanent land-use impacts, the most significant sources of environmental impact from conventional oil and gas operations are fluid releases (including gas) associated with well and pipeline failures and other liquid spills. Sulphur dioxide and other emissions, especially from gas plants, are dealt with separately.

### OIL AND GAS WELL INCIDENTS

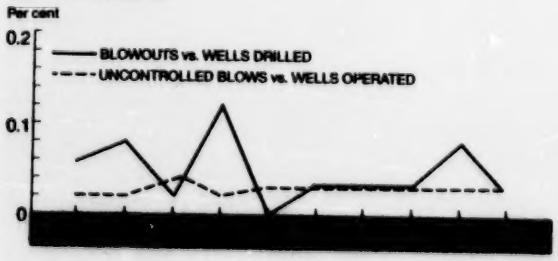
Well failures range from minor incidents to a few very serious failures involving environmental damage, injury to workers, substantial costs to the well owners, and extensive loss of valuable resources. For statistical purposes, major well failures are classified as either "blowouts" or "uncontrolled blows".

A blowout is defined as a complete loss of control at a *drilling* well. Uncontrolled blows are similar to blowouts except that they occur *after wells have been drilled* (at producing, suspended, or abandoned wells) and are characterized by complete loss of control.

Under these conditions, control can only be regained by the installation and use of special equipment, or by drilling a relief well.

During the last ten years, 23 blowouts have occurred in Alberta while drilling approximately 51 000 wells. These blowouts led to 1 fatality, 24 injuries, and often caused environmental damage or loss of resources and equipment. The trends in the occurrence of blowouts and uncontrolled blows are shown in **Chart 32, Well Incidents.**

32 Well Incidents




Uncontrolled blows occurred more frequently than blowouts during the last ten years. During the period there were 67 such incidents in Alberta, leading to 18 injuries, considerable equipment loss, and a number of undesirable environmental impacts, but no fatalities. There were 26 such incidents during well-servicing operations. Forty-one occurred during routine producing operations, or on wells where operations had been suspended. During this 10-year period, the number of wells in the province increased from 27 000 to 65 000.

Historically, the ratio of uncontrolled blows to wells operated has not fluctuated much (Chart 32). The annual average has been one uncontrolled blow for every 7000 active wells.

### LODGEPOLE INQUIRY

The blowout in October 1982 of a sour gas well near Lodgepole, some 40 kilometres (25 miles) west of Drayton Valley, led the ERCB to hold a public inquiry at Drayton Valley beginning on 1 November 1983.

Because there was considerable concern about the possible environmental effects of such a large sour gas blowout, and effects on the health of the residents in the area, a panel of six people was appointed to hear submissions from the concerned public and industry personnel. Included on the panel were two recognized medical authorities and the Executive Director of the Alberta Environmental Centre as well as three members of the ERCB, including its Chairman. The Chairman of the ERCB chaired the inquiry. Several studies were made to provide background information for the inquiry. These studies, performed by specialists working on behalf of committees representing the public, were funded by the ERCB. The ERCB also assisted in defraying costs incurred by representatives of the public in developing and presenting their submissions.

The Lodgepole inquiry was conducted in two phases, with the first phase considering the particular blowout incident and the second phase examining the control of blowouts in Alberta generally.

The inquiry generated considerable industry and public interest and the extensive submissions and discussions were not concluded until early 1984. The ERCB's report on Phase 2 of the inquiry, dealing with ways of reducing the occurrence of such blowouts, was issued in April 1984. The report on Phase 1 of the inquiry — on the particular incident and its effects — is to be issued later this year.

*Lodgepole Blowout Ablaze*

## PIPELINE LEAKS AND BREAKS

Of those pipelines in the energy industries which are within the ERCB's jurisdiction, the incidence of leaks and breaks in 1983 was typical of that in other recent years. Pipelines which extend beyond the Alberta border and under the jurisdiction of the National Energy Board, and low-pressure gas distribution lines which are administered by Alberta Utilities and Telecommunications are excluded. Since the ERCB requires pipeline operators to report all leaks and breaks, regardless of cause, magnitude, or consequence, for the pipelines under its administration, a comparison can readily be made of such incidents among the types of pipelines affected. **Chart 33, Pipeline Leaks and Breaks by Line Type,** presents such a comparison for 1983. About three-quarters of all leaks and breaks occurred on water lines and multiphase lines[3], while nearly one-quarter involved sweet gas lines and oil lines. A very small percentage occurred on sour gas lines, reflecting the high design standards applicable to such lines.

The frequency of pipeline leaks and breaks for all operating pipelines in Alberta, in 1983, averaged four incidents per 1000 kilometres (620 miles) of operating pipeline. The frequency of incidents, by category of fluid transported, was greatest for water lines, at 20 per 1000 kilometres operated, followed by 8 per 1000 for multiphase lines, 2 per 1000 for oil lines, and 1 per 1000 for gas lines.

**Chart 34, Distribution of Pipeline Leaks and Breaks,** shows the distribution of leaks and breaks by major cause in 1983. Corrosion, both internal and external, accounted for more than half the incidents, a rise of about 9 per cent from the previous year. The total of the incidents in "third party" and "other" categories declined the same percentage from the 1982 figure.

Water lines and multiphase lines accounted for most of the corrosion leaks in 1983, with two-thirds of all internal corrosion leaks occurring on water lines, and over one-half of the external corrosion leaks occurring on multiphase lines. For water lines, internal corrosion is a direct result of the fluid transported, and pipe manufacturers and operators are continually investigating different materials and techniques to reduce this type of corrosion. Multiphase lines (flow lines) present a different problem. Many of these lines were constructed without the coatings and other corrosion protection required for such lines today. Present-day standards ensure that proper external protection is provided on new lines, and periodic reviews of all operating lines are mandatory.

The number of leaks and breaks occurring due to other causes, including third-party damage, declined.

3 Pipelines containing oil, gas, and water, or any two of these three fluids.

## LIQUID SPILL CONTAINMENT AND RECOVERY

The number of liquid spills in Alberta, in 1983, increased slightly to 926, from 915 the previous year **(Chart 35, Amount of Liquids Spilled)**. However, the volumes spilled, both of salt water and liquid hydrocarbons, were significantly reduced. Salt water volumes of 6974 cubic metres (43 870 barrels) were about half those of the previous year, and liquid hydrocarbon volumes were greatly reduced, at 5863 cubic metres (36 870 barrels) as compared with 29 770 cubic metres (187 300 barrels) in 1982. As in 1982, pipeline breaks accounted for 49 per cent of the spills. Production facilities were responsible for 21 per cent, and individual wells for 20 per cent. The remaining 10 per cent resulted primarily from vandalism, operator error, and neglect.

The company operating the affected facility is responsible for taking action should it become necessary. Company personnel at the spill site are responsible for ensuring the safety of all employees, contractors, the public, domestic animals, and wildlife. They must also locate the source of the spill, shut it in safely, and begin containment and clean-up as quickly as possible.

If the operating company cannot be immediately identified, or does not have the personnel available to properly handle the spill, the ERCB assumes responsibility for initiating appropriate action. In most cases, this would involve requesting personnel and equipment from the local Oil Spill Co-operative.

## OIL SPILL CONTROL CO-OPERATIVES

Local Oil Spill Co-operatives are part of a province-wide network of 24 regions covering all oil-producing areas. The umbrella organization for these co-ops is the Prairie Region Oil Spill Containment and Recovery Advisory Committee (PROSCARAC) which, in turn, is part of a Canada-wide organization for oil spill containment and recovery.

The local co-operatives are composed of oil industry personnel and their organizations who provide funds and knowledge and volunteer their time. These co-operatives maintain oil spill equipment, conduct annual training exercises, and develop skill contingency manuals for their areas. These co-operatives are highly skilled and well prepared to respond to most emergency situations within their local areas.

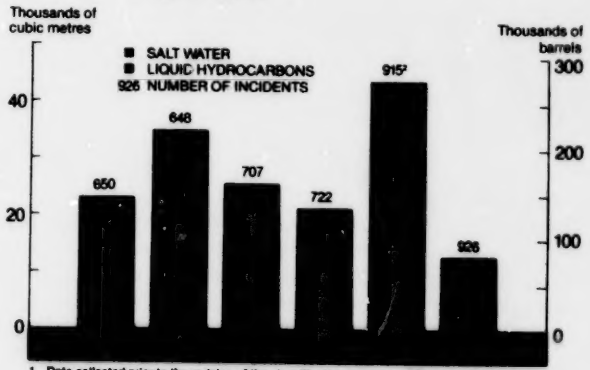
If an oil spill is major, the nearest local co-operative may request additional assistance from the PROSCARAC group which maintains equipment trailers (known as "OSCARS") throughout the western provinces. At the present time, there are nine specially-equipped OSCAR trailers located in Alberta.

PROSCARAC, through its various volunteer subcommittees, also provides worker training, including related manuals, information brochures, and spill exercises. PROSCARAC also distributes information on the results of significant new research on oil spill containment and recovery.

## RECLAMATION

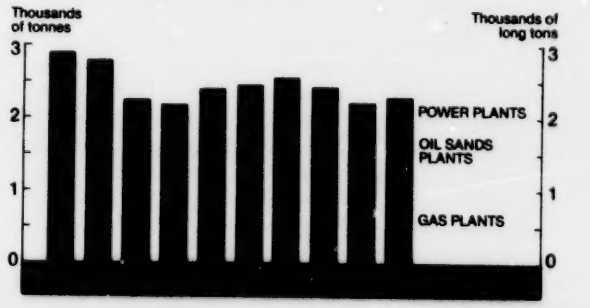
Reclamation after an oil spill is the responsibility of the operating company. Major spills in the province require a formal written reclamation program approved by the ERCB. The major concern in site restoration is to keep the spill-contaminated material in place and on the surface of the land or water. This makes it relatively easy to access and monitor the spill until final reclamation can be made.

35 Amount of Liquids Spilled [1]




1. Data collected prior to the revision of the classification system in 1978, are omitted due to unreliability.
2. Includes spills at Lodgepole, Lemming and Twinning.

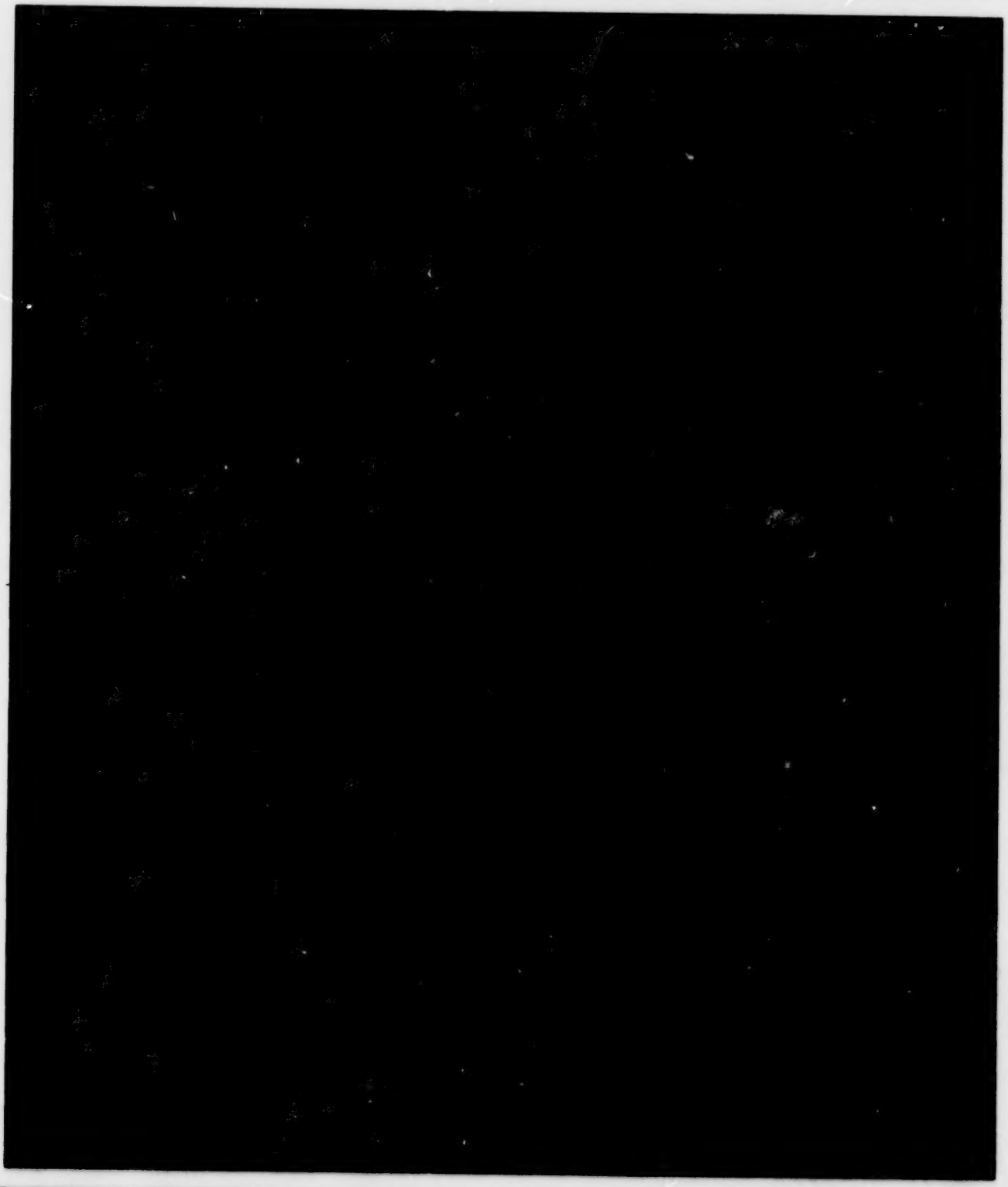
36 Sulphur Atmospheric Emissions




## ATMOSPHERIC EMISSIONS AND THEIR CONTROL

Although 5.5 million tonnes of sulphur were recovered in Alberta in 1983, 231 000 tonnes of sulphur (633 tonnes per day) were emitted to the atmosphere from sour gas plants, synthetic crude oil plants, and thermal power plants **(Chart 36, Sulphur Atmospheric Emissions)**. Nitrogen oxide ($NO_x$) emissions — which last were estimated in 1980 — were then thought to be about 900 thousand tonnes, or 2.5 thousand tonnes per day. Nitrogen oxide emissions occur principally from internal combustion engines.

While a considerable amount of sulphur was emitted to the atmosphere, the emissions were widely dispersed and the air quality standards were met.



*Alberta Gas Ethylene Plant at Joffre*

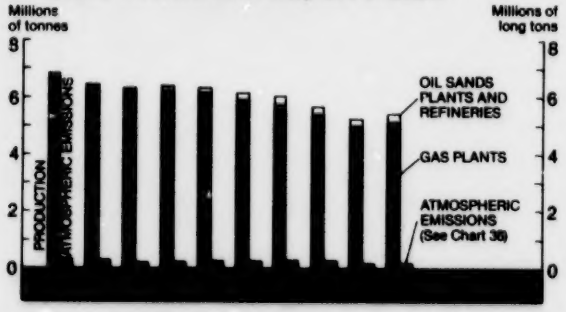
The air quality standards and policies developed by Alberta Environment, and the ERCB, consider the possible impacts of sulphur emissions on human beings and on the environment. These policies emphasize the following:

- The establishment of
  (a) air quality standards that protect human health and the environment,
  (b) plant emission standards to minimize emissions, based on the best practical technology, and
  (c) safety standards for the operation of related facilities, to ensure minimum risk to the general public.
- The surveillance of plant operations to ensure standards are met.
- The provision of a public hearing and inquiry process to permit public input and exchange of views.
- The conduct of research to improve the technology.

Most sulphur is released to the atmosphere as sulphur dioxide after the incineration of hydrogen sulphide. The sulphide dioxide concentration in the atmosphere, considered acceptable under Alberta standards, is 0.17 parts per million over a 1-hour period. This standard is twice as tough as the Canadian standard which, in turn, is among the most stringent in the world.

Public concern respecting acid rain has led to controls on actual emissions as well as on air quality.

37 Sulphur Production and Atmospheric Emissions




With a view to reducing total sulphur emissions in Alberta, in the late 1960s, the ERCB, in co-operation with Alberta Environment, reviewed sulphur recovery rates for sour gas plants and the feasibility of increasing them. As a result, in 1971 the ERCB imposed new limits on sulphur emissions and specified new minimum sulphur recovery efficiencies. Average sulphur recovery efficiencies, at gas processing plants that recover sulphur, increased from 95.9 per cent in 1971 to 97.9 per cent in 1983 **(Chart 37, Sulphur Production and Atmospheric Emissions).**

The ERCB and Alberta Environment continued to evaluate technological developments during the 1970s and, in 1980, a new guideline was issued which further increased the required minimum sulphur recovery efficiencies. Yet another review initiated in 1983, of more recent technical developments, suggests that still higher sulphur recovery efficiency requirements may soon be justified. A more detailed review of the suitability of the 1980 guideline is presently under way.

## RESOURCE AND URBAN DEVELOPMENT CONFLICTS

Approximately 70 per cent of Alberta is underlain by producible oil and gas reserves, although production is not being obtained from all of this area at the present time. Additional areas have potentially valuable coal deposits. Continued development in the province, stimulated to a considerable extent by the development of energy resources, has led to the gradual expansion of urban areas. This, in turn, has led to competing land uses as residential, industrial, and commercial development has radiated outward, and resource developments have expanded toward urban centres. This "competition" has been most serious around Calgary and, to a lesser extent, Edmonton, although smaller municipalities also have been affected. In consequence, certain prospective energy resource developments, located near urban areas, may prove impractical because of the two or more decades required to produce the energy resource and the early need to use the land for urgent urban development. In other instances, where resource development is proceeding, such urban developments may be possible, but will require accelerated depletion of the energy resources so that the urban development can proceed safely, reasonably soon.

Approximately 23 per cent of the remaining recoverable reserves of gas and oil in Alberta contain hydrogen sulphide, ranging from only a trace up to 90 per cent. The ERCB has attempted to establish appropriate developmental guidelines and regulations in order to resolve existing and potential land-use conflicts, and to avoid unacceptable risks to the public. The ERCB, pursuant to the Subdivision Regulations under the Planning Act, is informed of where community development is being considered. It advises planning authorities where sour gas reserves and associated sour gas facilities are situated, and makes recommendations to the Subdivision Approving Authority respecting any proposed new developments near them.

The ERCB has developed a set of guidelines respecting safe setback distances between sour gas facilities, in particular categories, and urban developments. The sour gas level relates to the amount of emissions that could occur from facilities in the category. These guidelines are also reflected in the Subdivision Regulations. The following table shows the designated setback distances.

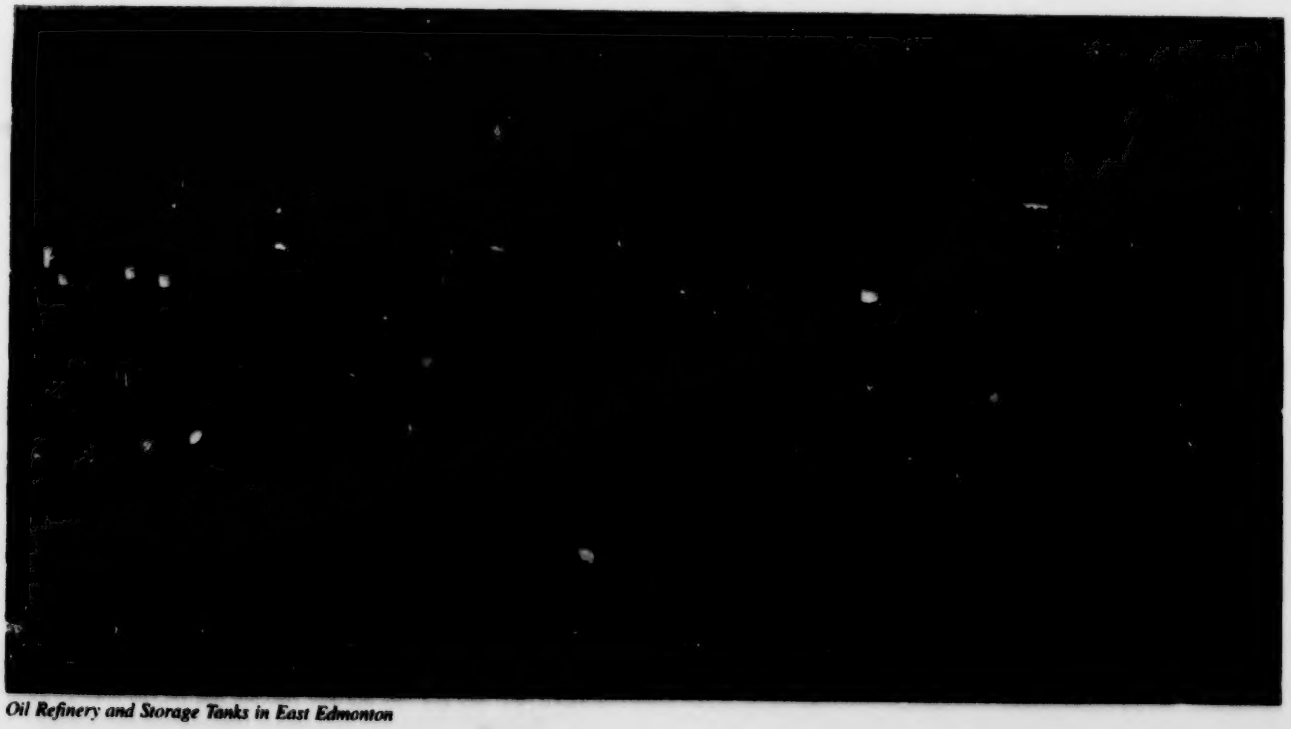
Required Distance Between New Sour Gas Facilities and Residential and Other Developments

| SOUR GAS LEVEL | SOUR GAS RELEASE WELL RELEASE RATE cubic metres per second | SOUR GAS RELEASE OTHER FACILITIES RELEASE VOLUME cubic metres | MINIMUM DISTANCE TO VARIOUS DEVELOPMENTS kilometres |
|---|---|---|---|
| 1 | less than 0.3 | less than 300 | 0.1 km from sour gas wells (No minimum distance to other facilities) |
| 2 | 0.3-2.0 | 300-2000 | 0.1 km to individual dwellings and unrestricted country development (sparse rural residences)<br>0.5 km to urban centre or public facility |
| 3 | 2.0-6.0 | 2000-6000 | 0.1 km to individual dwellings, up to 8 dwellings per quarter section<br>0.5 km to unrestricted country development<br>1.5 km to urban centre or public facility |
| 4 | greater than 6.0 | greater than 6000 | As specified by the ERCB but not less than for Level 3 |

In 1983, the ERCB considered urban development plans in northeast Calgary (Saddle Ridge), and west Edmonton, which would be near existing sour gas or oil facilities. During the year, an inquiry also was held at Okotoks to consider a proposed gas plant and the anticipated impingement of future energy resource exploration and production on existing and future urban development. In each inquiry, the ERCB considered the feasibility of urban development and oil and gas operations co-existing in the same area. It also investigated the steps the various parties should be required to take to facilitate co-existence.

In west Edmonton, and northeast Calgary, the ERCB concluded that resource and urban development could co-exist without seriously affecting the safety of the general public. However, careful planning and special safety measures would be necessary. The ERCB, in these instances, made recommendations related to specific setback distances, special construction considerations, public awareness programs, and the careful timing of urban development activities in the case of northeast Calgary.

The formation of a liaison committee for each area was also recommended by the ERCB. These committees may include representatives from the oil and gas operators in the development area, the planning authorities, Alberta Environment, and the ERCB. The committees will consider concerns raised by the interested parties including the need to improve communication between the public, land-use planners, and the energy industry. They will suggest planning guidelines respecting energy resource development and other land use, and propose means to resolve any conflicts, and satisfactorily plan energy resource extraction and urban development.



*Oil Refinery and Storage Tanks in East Edmonton*

# Resource Management

**. . . how Alberta optimizes its resources**

## RESOURCE RECOVERY

### ENHANCED RECOVERY OF OIL

Only 20 per cent of the oil in place in Alberta reservoirs would be recovered if only natural production methods were applied. Enhanced-recovery schemes enable oil production rates to be increased, or sustained longer than with natural energy sources alone. Enhanced recovery involves the injection of fluid into a petroleum reservoir to supplement the natural energy drive mechanisms, thereby helping push the oil to the producing wells and thence to the surface. This differs from primary recovery where production occurs under the natural drive mechanisms, such as solution gas drive, gas cap expansion, and water drive.

An extensive knowledge of the natural recovery mechanisms, and their expected performance in a petroleum reservoir, must be acquired before determining the need for the various enhanced-recovery techniques. This knowledge also is necessary to determine the best time to implement an enhanced-recovery scheme in a particular reservoir. The ERCB therefore encourages the systematic gathering and documentation of all basic production and reservoir data required to evaluate the primary (natural) recovery mechanisms at work in each reservoir.

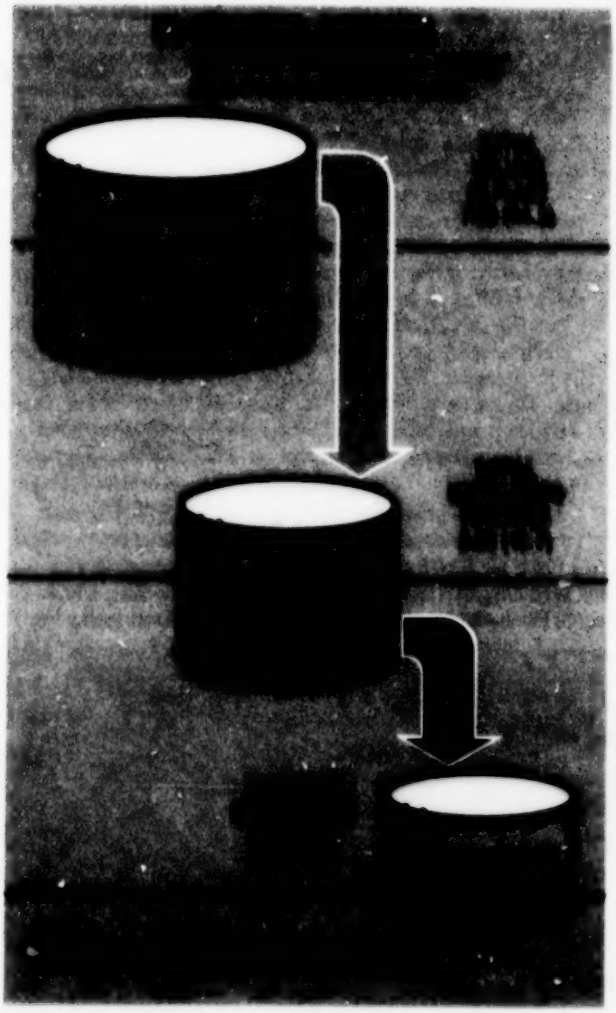
Water is the most frequently used injection fluid in enhanced-recovery schemes since it is usually inexpensive, readily available, and reasonably effective in most Alberta petroleum reservoirs.

Water has been an effective enhanced-recovery fluid. However, programs involving the injection of more expensive fluids, such as natural gas or liquefied petroleum gases or steam, will yield greater oil recoveries in selected reservoirs. Natural gas is used in certain high pressure reservoirs, and natural gas enriched with liquefied petroleum gases in other lower pressure reservoirs containing denser oil. These fluids readily mix with (are miscible with) the oil and displace most of the oil from the rock pores contacted in such miscible floods.

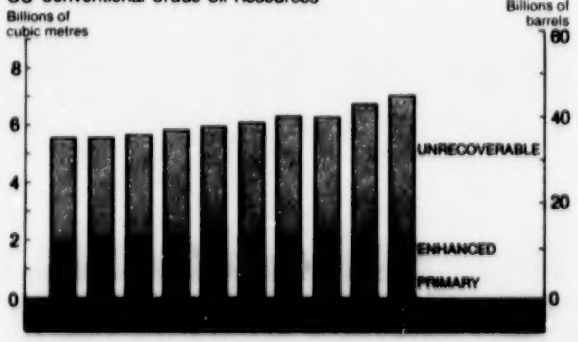
**Chart 38, Crude Oil Reserves,** shows 7.02 billion cubic metres (44.2 billion stock tank barrels) of conventional crude oil have been found in Alberta. Of that total, 29 per cent is recoverable; approximately 20 per cent by primary recovery mechanisms and 9 per cent through enhanced-recovery operations. **Chart 39, Conventional Crude Oil Resources,** shows the growth in Alberta conventional crude oil resources since 1974. About 67 per cent of the recoverable portion already has been produced.

Average recoveries of 32 per cent for light-medium crude oil, and 10 per cent for conventional heavy-density crude oil, are being achieved through a combination of natural and enhanced-recovery methods.

Recent royalty reductions by the provincial government and tax changes by the federal government, together with greater availability of natural gas, have increased the number of applications to the ERCB for approval of tertiary-recovery schemes. During 1983, 13 applications for enhanced recovery, involving miscible flooding techniques, were approved or were being evaluated. These miscible flood schemes were proposed in a variety of situations ranging from new pools currently under primary depletion to mature pools where the technique is expected to recover oil left behind following waterflood operations.



39 Conventional Crude Oil Resources



### CONSERVATION OF SOLUTION GAS

Solution gas is the gas which is released from crude oil as it is brought from the reservoir to the surface. In some reservoirs, gas cap gas also may be produced with the oil unintentionally. Such gas cap gas production normally would be included with the solution gas production.

**Chart 40, Solution Gas Production,** illustrates the progress made during the last ten years in conserving solution gas. Solution gas conservation has increased from 87 per cent in 1974 to 91 per cent in the period 1977-1983. The high level of conservation in recent years has been achieved through the co-operative efforts of the industry and the ERCB. Also, extension of pipeline facilities and increases in gas and co-product prices have made it economical to conserve solution gas from smaller oil fields.

40 Solution Gas Production

## THE ST. ALBERT-HOMEGLEN-RIMBEY REEF TREND: AN ENERGY SUCCESS STORY

In 1947, after a long period of relatively unsuccessful exploration in western Canada, Imperial Oil Limited made a major discovery: the Leduc-Woodbend Field. This discovery established that Devonian limestone reefs, containing large oil and gas reserves, could be present along a trend in central Alberta. The great potential of this field was in itself cause for celebration. But, in the period of extensive exploration that followed, the initial Leduc-Woodbend discovery was found to be just the first pot of black gold in a series, or trend, that extends southwest from St. Albert through Leduc-Woodbend to Homeglen-Rimbey. The principal reefs in this trend are shown in **Chart 41, Leduc-Woodbend D-3A Pool and the Golden Trend.**

Underlying the reef trend is the Cooking Lake Formation which contains water and is present over a large area of south and central Alberta. The water in the formation is in communication with, and provides an efficient energy source for production of, the Devonian oil and gas pools. The companies working along the trend, assisted by the ERCB, co-operated in the development of an efficient plan for the production of the pools to achieve their greatest potential. In Leduc, for example, the operators agreed to unitize the pool. Under this program, each participating owner received a fixed share of the oil and gas produced for the remaining pool life regardless of how much each individual well produced.

During the first 37 years of production from the Leduc-Woodbend D-3A Pool, the primary focus of operations was the recovery of the pool's oil reserves. The companies were required to conserve gas produced along with the oil in this pool, as in all others where practical, even though oil was the primary target. In addition, the companies were penalized for producing excessive amounts of gas or water with the oil they produced. The penalties encouraged the efficient use of the energy.

After 37 years, the oil column in the reef at the Leduc-Woodbend Pool had shrunk from 11.6 metres (38.1 feet) to a thin 2.0 metres (6.5 feet). At this stage in the production process, it was no longer feasible to produce oil without also producing large amounts of water and gas. With the oil column thus reduced to the minimum practical thickness, emphasis shifted in 1984 to the recovery of the overlying gas reserves.

In 1983, the ERCB approved a plan for the Leduc-Woodbend D-3A Pool which would allow, for the first time in the pool's history, the production of large amounts of gas from the gas cap with the oil without penalty. The gas cap will be produced at a high rate to reduce the pool pressure. This rapid reduction of pressure (or drawdown) will reduce the amount of gas in the rock spaces before water enters them. Gas recovery will be increased by minimizing the amount of gas trapped. Some of the remaining oil will be conveyed to the wells and produced along with the gas.

The rapid reduction in pressure at Leduc-Woodbend also ordinarily would reduce the pressure somewhat at nearby pools north and south of Leduc-Woodbend and tend to reduce oil recovery there. However, this effect will be largely avoided by injecting water below the oil at Acheson and Wizard Lake fields.

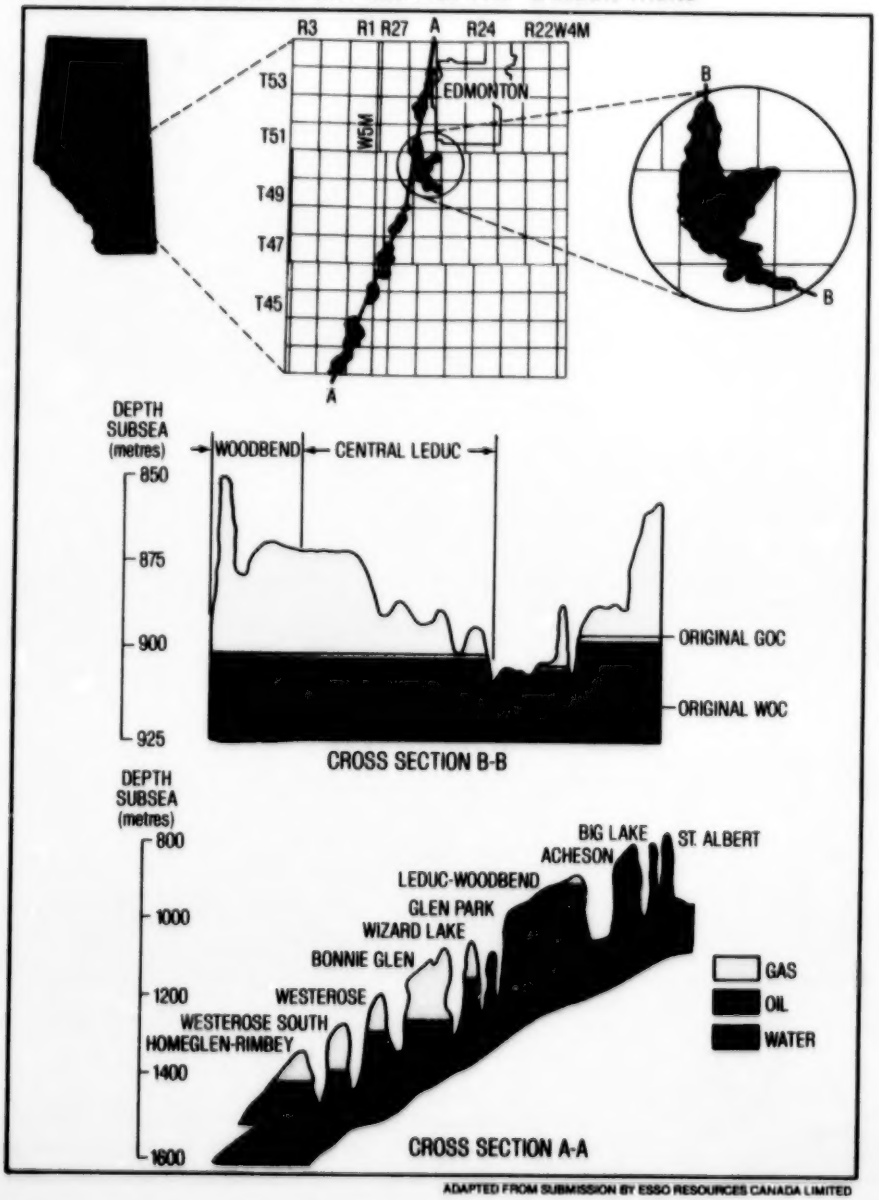
With most of the oil, and some of the gas in the trend, already produced, experience has confirmed the earlier projections of exceptionally high recovery rates. The average oil recovery efficiency of the trend is almost 70 per cent, compared to the provincial average for light-and medium-density crude oil of 32 per cent. Gas recoveries in the reef trend, at more than 80 per cent, also exceed the provincial average of 72 per cent.

Finding markets for the large amounts of gas to be produced, when markets for gas are depressed, poses a problem. To overcome this, a portion of the gas produced at the Leduc-Woodbend Pool will be stored in the gas cap of the nearby Golden Spike Pool, on the edge of the main reef trend. The Golden Spike Pool is largely separated, by a dense section, from the main Cooking Lake water-bearing zone, thus its oil and gas recovery will not be affected by encroaching Cooking Lake water.

The achievements in recovering oil and gas from this reef trend are remarkable when compared to efficiencies normally encountered in Alberta, and indeed, throughout the world. The outstanding quality of the D-3 reservoirs in this trend is nature's gift, of course. But, the attention to detail, and the co-operative work of the industry and the ERCB, have assisted greatly in achieving the high recovery of the resource. Here are some of the special production practices and programs that have helped make the story of this reef trend a resounding success:

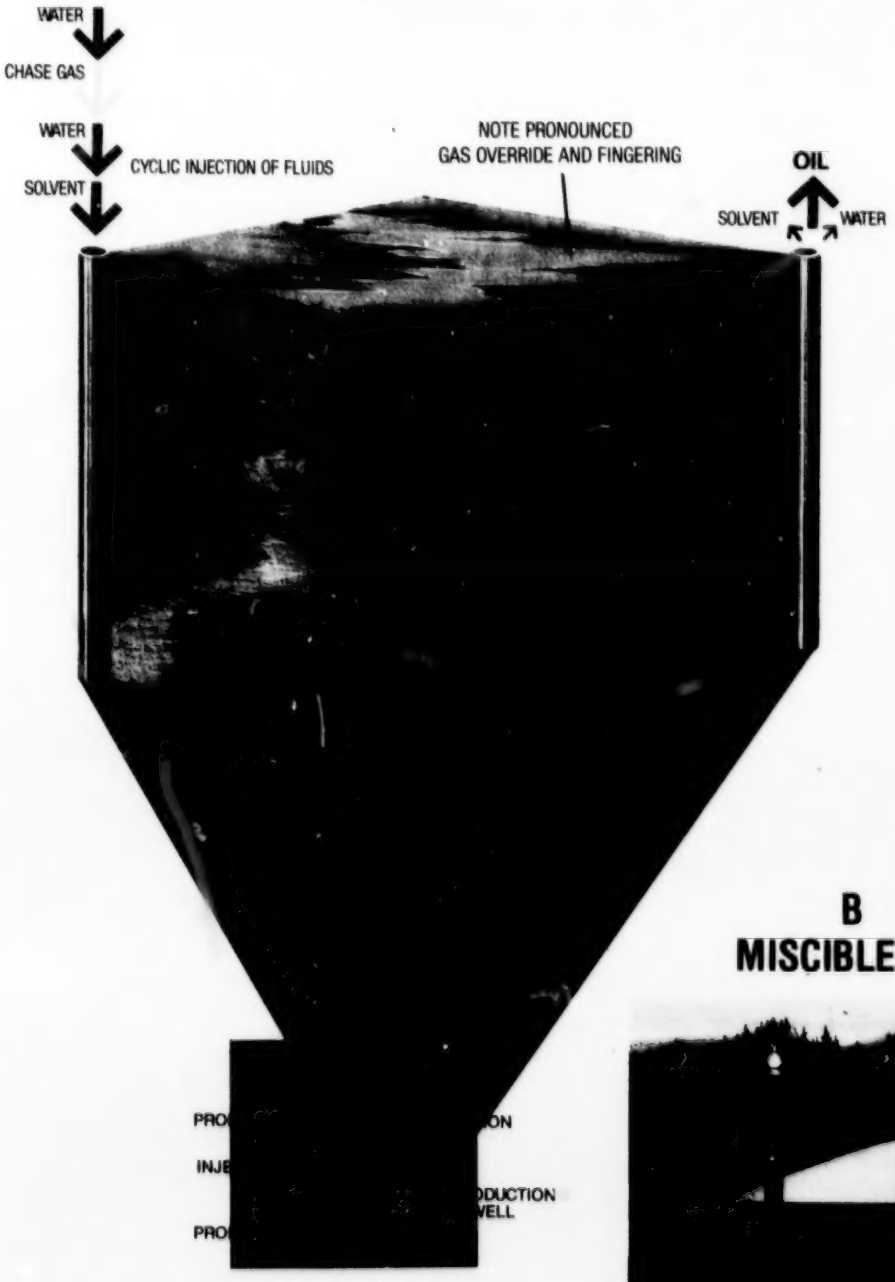
1. Production of the gas caps was deferred so as to maintain the pressure necessary to control movement of the oil and permit its efficient production.
2. Gas and water are injected in the reefs at appropriate locations to assist the natural water drive in maintaining the reservoir pressure near the optimum level.
3. Wherever an oil column is situated between a gas cap and bottom water, injection of water and gas are balanced to maintain the oil in the best position. This allows oil production to be continued with the minimum amount of water and gas production.

## 41 LEDUC - WOODBEND D-3A POOL AND THE "GOLDEN TREND"

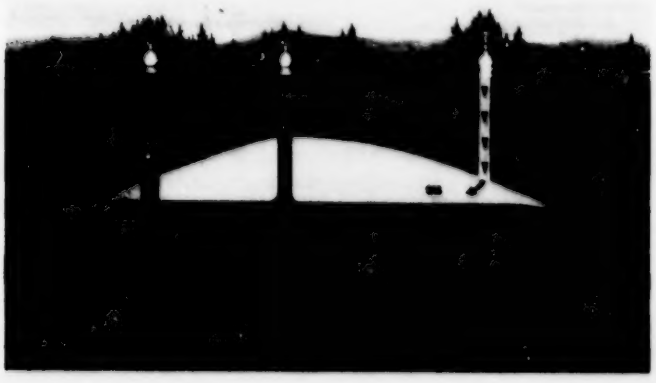



ADAPTED FROM SUBMISSION BY ESSO RESOURCES CANADA LIMITED

## A HORIZONTAL MISCIBLE DISPLACEMENT




## B VERTICAL MISCIBLE DISPLACEMENT



4. The wells in most pools have been grouped in operating units to permit optimum recovery from the pool as a whole rather than emphasizing the recovery from individual wells. Most of the production, therefore, occurs at the most efficient wells.
5. In the Golden Spike and Wizard Lake pools, blankets of natural gas liquids have been injected above the oil zone and then pushed downward by the injection of gas **(see Chart B, Vertical Miscible Displacement).** The natural gas liquids act as a solvent, and are more efficient than water in recovering the oil from the rock pores. This expensive process, known as "miscible displacement" **(Charts A and B, Horizontal and Vertical Miscible Displacement),** was discontinued at the Golden Spike pool because of a thin horizontal section of impermeable rock in much of the pool. The continuity and effectiveness of this barrier was not evident when the project was planned. The impermeability of the barrier prevented the uniform downward advance of the solvent blanket.
6. In the Bonnie Glen Pool, production of the gas cap was permitted in order to remove the high content of valuable natural gas liquids. The residue gas is being returned to the reservoir to maintain pressure. This procedure permits earlier and increased recovery of the natural gas liquids contained in the gas cap without restricting the recovery of oil.

## SUPPLY

### CONVENTIONAL CRUDE OIL

#### Reserves

During 1983, pool discoveries, additions to existing pools, new enhanced-recovery schemes, expansions to existing enhanced-recovery schemes, and the reassessment of existing primary depletion and enhanced-recovery reserves, all contributed to an increase of 64 million cubic metres (403 million barrels) in the province's initial established reserves of conventional crude oil **(Chart 42, Conventional Crude Oil Reserves and Production).** Conventional crude oil production totalled 56 million cubic metres (352 million barrels), resulting in a net increase in remaining established reserves of 8 million cubic metres (50 million barrels) to 658 million cubic metres (4.14 billion barrels). This represents the first net increase of reserves since 1969 and resulted mainly from the generally favourable performance of a number of significant, older primary-depletion, and enhanced-recovery pools.

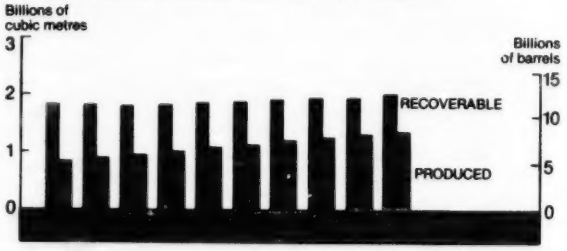
Initial established reserves from primary depletion mechanisms increased by 46.2 million cubic metres (290.7 million barrels). Of this amount, pool discoveries, and additions to existing pools, accounted for 21.4 million cubic metres (134.7 million barrels), while re-evaluation of the reserves of existing primary pools added 24.8 million cubic metres (156 million barrels) to the province's reserves. In addition, new enhanced-recovery schemes added 12.1 million cubic metres (76.1 million barrels), while re-evaluation of existing schemes contributed a further 5.8 million cubic metres (36.5 million barrels), resulting in a total increase of 17.9 million cubic metres (112.6 million barrels) from enhanced-recovery mechanisms.

#### Potential

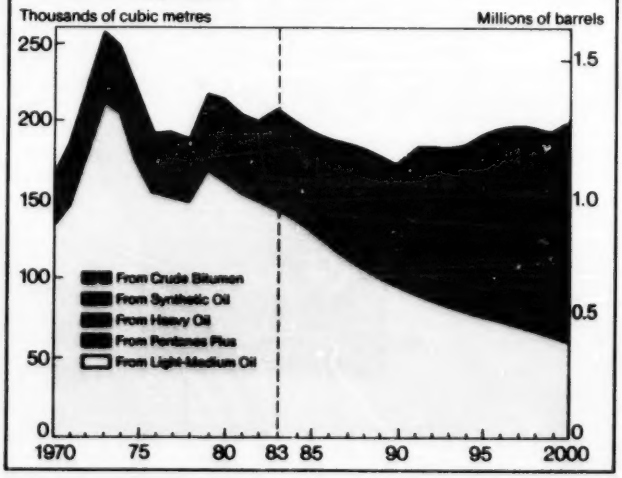
The ultimate potential of conventional crude oil in Alberta has been estimated to be between 2.4 billion cubic metres (15.1 billion barrels) and 2.7 billion cubic metres (17.0 billion barrels). Adjusting the forecast in ERCB Report 83-E to include year-end 1983 reserves and production data, gave a more specific estimate of ultimate potential, of 2.67 billion cubic metres (16.8 billion barrels). Seventy-five per cent of the ultimate potential consists of proved reserves, 50 per cent of which already have been produced. The resulting remaining ultimate potential is 1.3 billion cubic metres (8.2 billion barrels).

The breakdown of the province's ultimate potential of crude oil reserves, and a forcast of productive capacity from those reserves, is presented in ERCB Report 83-E.

42 Conventional Crude Oil Reserves and Production




43 Total Daily Productive Capacity of Alberta Crude Oil and Equivalent



### Productive Capacity

Production of conventional crude oil averaged 151.1 thousand cubic metres (953 thousand barrels) per day during 1983, which was approximately 92 per cent of productive capacity. If production could continue at the 1983 level, the remaining established reserves in the province would be produced in 12 years. However, the ERCB forecasts that the productive capacity of conventional crude oil will steadily decline in view of the declining rate of reserve additions, to 73 thousand cubic metres (459 thousand barrels) per day by the year 2000. Thus, these reserves will require considerably longer than 12 years to be fully produced. The new reserves added during this period also will contribute to the extension of production into the next century.

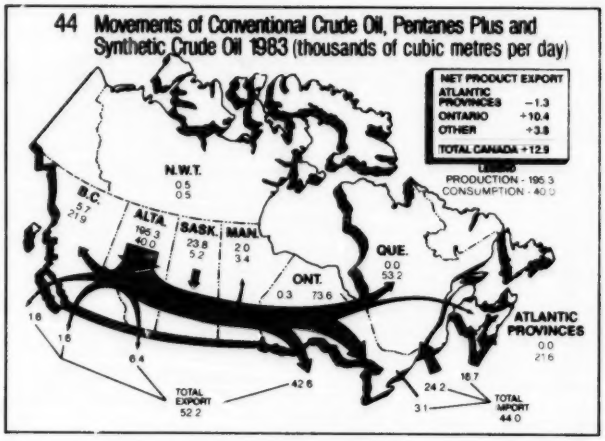
The ERCB issued its latest forecast of the supply of crude oil in early 1984. The projections from that report are shown in **Chart 43, Total Daily Productive Capacity of Alberta's Crude Oil and Equivalent.** Although the production of light-medium and heavy crude oil is projected to decline to less than half the current rate by the year 2000, substantial amounts of conventional crude oil are expected to be found and developed. More than half the production of conventional crude oil projected for the year 2000 is expected to come from reserves to be added between 1983 and 2000.

Chart 43 also shows the substantial growth in the production of bitumen and synthetic crude oil from the oil sands of northern Alberta. Synthetic crude oil is expected to almost offset the decline in production of conventional crude oil between now and the year 2000. Most of the bitumen will be upgraded in Alberta to synthetic crude oil, but some will be removed from the province after having been blended largely with pentanes plus, a volatile liquid recovered from natural gas. The addition of pentanes plus to the raw bitumen makes it sufficiently fluid, at ordinary temperatures, to be transported through pipelines. The bitumen and synthetic crude oil will be produced from oil sands mining projects, and in situ recovery projects, mainly in the Cold Lake, Athabasca, and Peace River deposits. The in situ projects involve heating the bitumen in the reservoir to make it flow more readily and then pumping it to the surface through wells. The first such commercial project already is being developed by Esso Resources near Cold Lake.

### Disposition of Crude Oil and Equivalent
### . . . where our crude oil goes

**Chart 44, Movements of Conventional Crude Oil, Pentanes Plus, and Synthetic Crude Oil,** shows the major role of crude oil from Alberta in the total Canadian supply. In 1983, almost all of the Canadian production came from western Canada, and about 86 per cent of that from Alberta. As a result of the decline in demand, related partly to the recession and partly to conservation measures, Canada was

44 Movements of Conventional Crude Oil, Pentanes Plus and Synthetic Crude Oil 1983 (thousands of cubic metres per day)



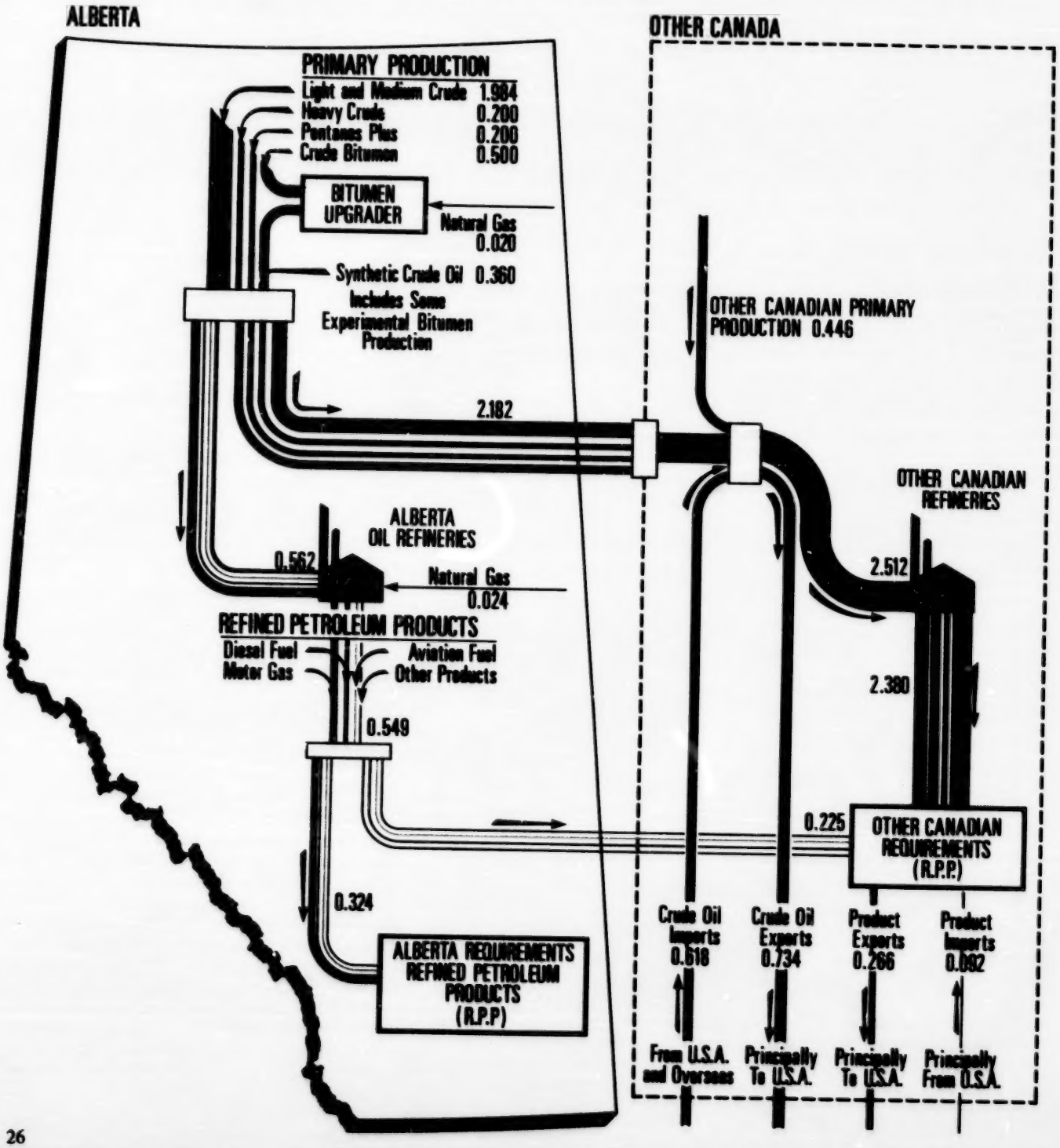

self-sufficient in crude oil in 1983. In fact, the trade in crude oil yielded a small net export balance amounting to about 4 per cent of the total supply. This surplus was exported principally to the United States and was comprised mainly of heavy crude oil.

**Chart 45, Flows of Crude Oil and Refined Petroleum Products in 1983,** shows the flows of Alberta crude oil in 1983 by type, the portion which is refined in Alberta, and its role in meeting the requirements in Alberta and the total Canadian requirements for refined petroleum products. Approximately 20 per cent of the total Canadian requirements for refined petroleum products are supplied from Alberta. The refineries in Alberta produce mainly motor gasoline and diesel fuel, whereas the refineries in some other parts of Canada produce products used as feedstock for the petrochemical industry. This results from the much heavier dependence of the petrochemical industry in eastern Canada on crude oil, rather than on natural gas, which is the energy resource on which the Alberta petrochemical industry is primarily based.

There has been considerable trade between Canada and the United States in refined petroleum products, especially in the southern Ontario, Michigan, Ohio, and New York areas. These exchanges have led to improvements in refining efficiency and have permitted seasonal changes in product demand to be better accommodated.

The closing of older, less efficient refineries in southern Ontario, Montreal, central British Columbia, and in the Maritime Provinces, in the face of declining markets, and the modern additions to refining capacity in Alberta in recent years, have considerably enhanced Alberta's role in supplying Canadian needs for refined petroleum products.

## 45 FLOWS OF CRUDE OIL AND REFINED PETROLEUM PRODUCTS 1983 (EXAJOULES)



## CRUDE OIL (AND EQUIVALENT) RESERVES FROM OIL SANDS

If the portion of the Athabasca oil sands deposit which lends itself to surface mining operations were developed and the production processed through plants of the Suncor and Syncrude type, 3.9 billion cubic metres (24.5 billion barrels) of synthetic crude oil ultimately could be produced. However, the portion of the oil sands deposit under active development in the Suncor and Syncrude projects would recover only 291 million cubic metres (1830 million barrels) of synthetic crude oil and, of this, 65 million cubic metres (409 million barrels) already has been produced. The remaining established surface mineable reserves of synthetic crude oil attributed to the Suncor and Syncrude projects, at the 1983 year-end, are therefore, 226 million cubic metres (1420 million barrels).

In the Cold Lake deposit, bitumen recoverable by in situ recovery methods is under active development by Esso Resources Canada. Similar experimental field demonstration projects also are under way in several other oil sands areas. This raw bitumen production is marketed without being upgraded to synthetic crude oil. The total remaining established reserves of crude bitumen credited to these programs are 12.1 million cubic metres (76.1 million barrels) of which one-third is attributed to Phases I and II of the Esso Resources program.

## MARKETABLE GAS

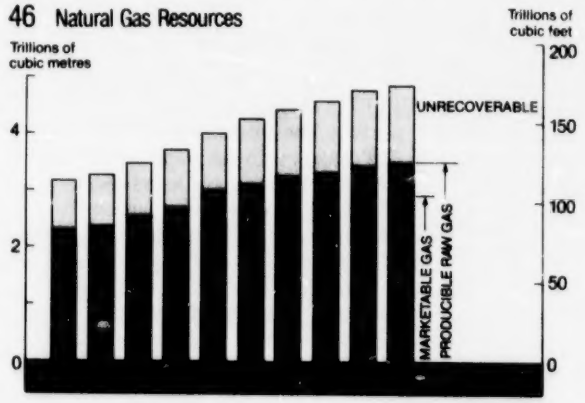
### Reserves

The initial established reserves of marketable gas in Alberta increased by 44 billion cubic metres (1500 billion cubic feet) to 3.04 trillion cubic metres (108 trillion cubic feet). **Chart 46, Natural Gas Resources,** shows that production totalled approximately 66.0 billion cubic metres (2.4 trillion cubic feet) for the year. This reduced the remaining established reserves by 26 billion to 1.90 trillion cubic metres (921 billion to 67.3 trillion cubic feet) **(Chart 47, Natural Gas Reserves and Production).**

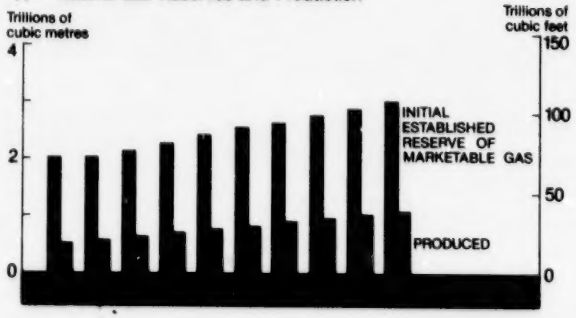
### Potential

The ultimate potential is 3.80 trillion cubic metres (135 trillion cubic feet) of marketable gas. Eighty per cent is established and 30 per cent has been produced already. The remaining ultimate potential is 2.66 trillion cubic metres (95 trillion cubic feet).

46 Natural Gas Resources




47 Natural Gas Reserves and Production



### Productive Capacity

The average 1983 production rate of 173 million cubic metres (6.1 billion cubic feet) per day compares to a productive capacity of 315 million cubic metres (11.2 billion cubic feet) per day. The gross plant capacity, as reported in the section dealing with gas plants in Exploration and Development, was 425 million cubic metres per day (15.1 billion cubic feet per day). Productive capacity is expected to rise gradually to about 400 million cubic metres (14.2 billion cubic feet) per day over the next 6 or 7 years and then decline to 250 million cubic metres (8.9 billion cubic feet) per day by the year 2000. Over that same period, consumption within the province is expected to rise from the current level of 40.6 million cubic metres (1.4 billion cubic feet) per day to 72.5 million cubic metres (2.6 billion cubic feet) per day by the year 2000.

## COAL

As shown in **Chart 48, Coal Reserves**, the initial established reserves of raw coal at year-end 1983 were 18.0 gigatonnes (3.7 and 14.3 gigatonnes of bituminous and subbituminous coal, respectively). Cumulative production of marketable coal totalled 451 megatonnes, resulting in remaining established reserves of 17.5 gigatonnes at year-end, an increase of 1.2 gigatonnes over 1982. The remaining established reserves comprise 3.5 and 14.0 gigatonnes of bituminous and subbituminous coal, respectively.

The ultimate potential of Alberta's raw coal is 820 gigatonnes, of which 2 per cent was established by year-end 1983. The ERCB expects the annual production of bituminous and subbituminous coal to increase to 28 and 22 megatonnes, respectively, by the year 2000.

## ELECTRICITY

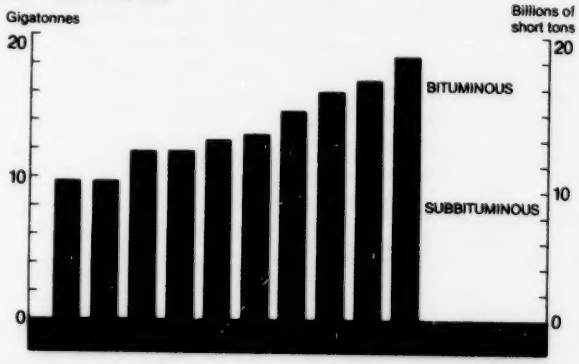
The facilities of Alberta's electric utilities are developed to accommodate the expected growth in demand for electric energy. Sufficient surplus capacity is maintained to provide satisfactory levels of service in the event of occasional plant and transmission line failures. In 1983, the total amount of electric energy generated by the electric utilities in the province was 26 358 gigawatt hours (GW•h). Of this amount, 1480 GW•h was generated by hydro plants, 22 851 GW•h using coal, 2014 GW•h using gas, and 13 GW•h using oil (Chart 30). The peak demand of 4438 megawatt hours occurred on 19 December 1983.

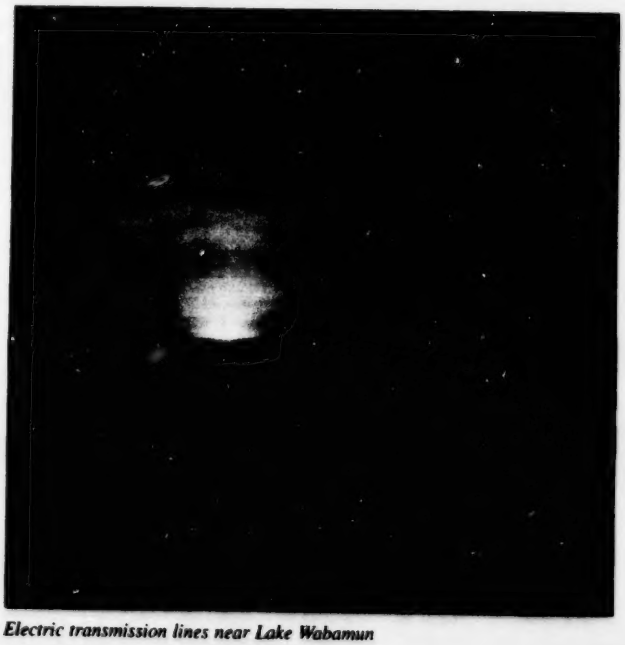
The amount of gas used as fuel in power plants, in 1983, decreased by approximately 18 per cent compared to 1982. This was mainly a result of the increased cost of natural gas relative to coal.

The ERCB expects Alberta's electric energy requirements to almost double, to approximately 50 000 GW•h, by the year 2000.

*New "Easi-Miner" at work in Obed Mountain Coal Mine*

48 Coal Reserves



*Electric transmission lines near Lake Wabamun*

# Revenues/Benefits

**. . . earnings and employment resulting from Alberta's energy resources**

## PRICES

The electric utilities in Alberta sold their electric energy for an average of 5.14 cents per kilowatt-hour in 1983. The increase in the cost of electric energy over the last ten years **(Chart 49, Price of Electricity)** has averaged 13.0 per cent per year, or 2.3 per cent per year if the effects of inflation are excluded.

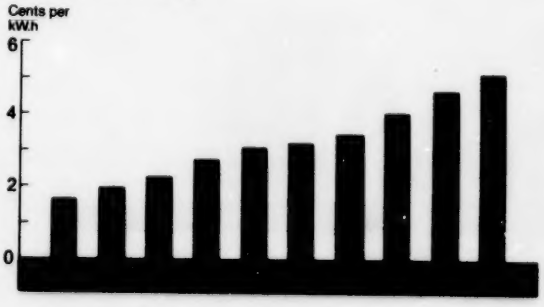
The average wellhead price of conventional crude oil increased by 28 per cent in 1983 **(Chart 50, Price of Crude Oil)** largely as a result of additional categories of crude oil being subject to NORP (new oil reference price) and the increasing amounts of new oil relative to old oil produced. These changes more than offset the decline of 7 per cent in NORP resulting from the corresponding decline of world crude oil prices. "Old oil" prices, in 1983, reached the ceiling of 75 per cent of the landed cost of imported oil in Montreal, which was set forth in the 1981 5-year energy pricing agreement between the Government of Alberta and the Government of Canada. The price of synthetic crude oil is totally eligible for NORP and declined similarly.

Average gas prices **(Chart 51, Price of Natural Gas)** remained stable in 1983. Increasing domestic prices were offset by reduced sales of gas at the higher export price.

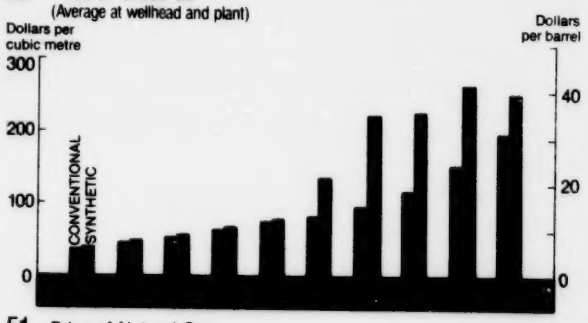
The world-wide recession reduced the markets for sulphur, especially in the fertilizer industry, and led to a 22 per cent decline in the average plant gate price **(Chart 52, Price of Sulphur).** However, demand for sulphur is likely to increase with economic recovery, and it now appears likely that prices of sulphur will resume their escalation.

Nearly all subbituminous coal production in Alberta is consumed by electric utilities at a price closely related to the cost of mining. However, most of Alberta's bituminous coal is produced for thermal and metallurgical markets outside Alberta and competes with coal from other countries. As a result, the quantities of bituminous coal marketed, and the prices received, tend to fluctuate even though most of the production is marketed under long-term contracts **(Chart 53, Price of Coal).** Prices in export markets have been weak recently and part of the gain in average price realized in 1983 may be lost in 1984.

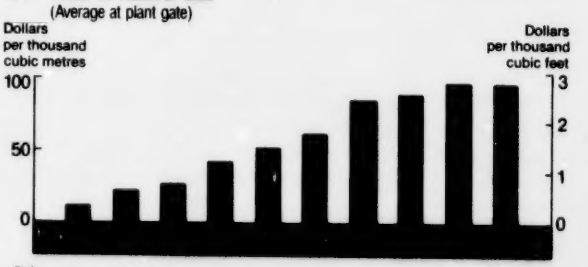
49 Price of Electricity




50 Price of Crude Oil
(Average at wellhead and plant)

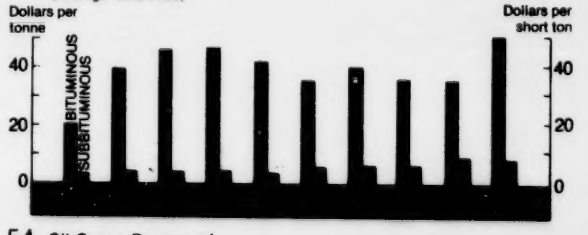



51 Price of Natural Gas
(Average at plant gate)

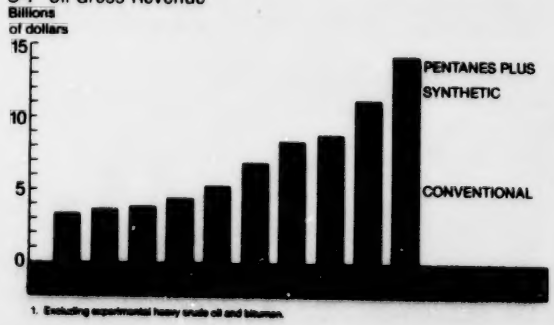



52 Price of Sulphur
(Average at plant gate)

53 Price of Coal
(Average Mine Price)




54 Oil Gross Revenue [1]




1. Excluding experimental heavy crude oil and bitumen.

## GROSS REVENUES

The total revenue of electric utilities increased in 1983 to $1221 million, although revenue growth was more modest than in the past.

The total revenue from the production of crude oil and equivalent in 1983 **(Chart 54, Oil Gross Revenue)** increased by 28 per cent, relative to 1982, reflecting increased production of conventional and synthetic crude oil and improved average prices for conventional crude oil. The decline in the price of synthetic crude oil slightly reduced the increase in total revenue due to the other changes.

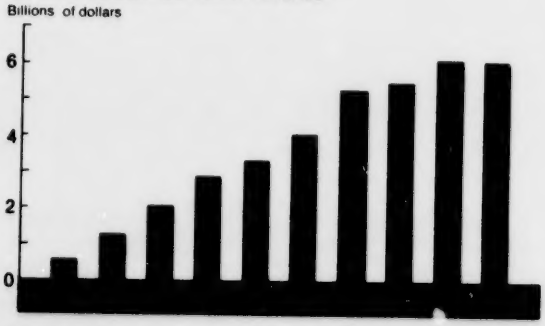
Revenue from gas production declined slightly **(Chart 55, Marketable Gas Gross Revenue)** as a result of the higher average sales price in Canada being more than offset by reduced sales in the higher-priced export market in the United States.

Sales of natural gas liquids generated increased revenue **(Chart 56, Natural Gas Liquids Gross Revenue)** as a result of increases in the prices of ethane, propane, and butanes, relative to their 1982 prices, and the recovery of a greater amount of ethane.

Sulphur revenue declined despite a small increase in production at gas processing plants and a substantial increase in production at synthetic crude oil plants **(Chart 57, Sulphur Gross Revenue).** The decline in revenue relative to 1982 reflected lower prices and sales.

Coal revenue **(Chart 58, Coal Gross Revenue)** also increased in 1983 as a result of increased sales of bituminous, metallurgical, and subbituminous coal, and improved prices for all types of coal. The outlook for coal revenue is less bright for 1984, with the quantities and prices uncertain, or likely to be lower for several overseas contracts.

55 Marketable Gas Gross Revenue




56 Sulphur Gross Revenue

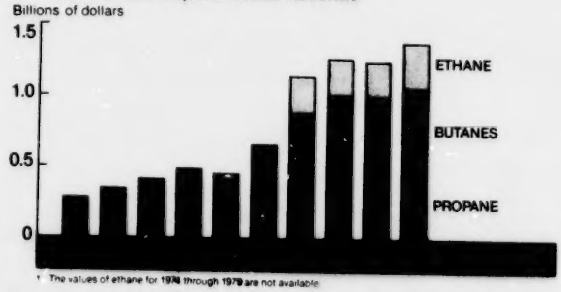
## EMPLOYMENT AND INVESTMENT

Statistics on investment and employment are more difficult to obtain than other statistics reported in this review. As a consequence, the data presented in these categories extend only to the 1982 year-end.

Both employment and investment declined in 1982 **(Chart 59, Employment in the Energy Industries** and **Chart 60, Annual Investment)** relative to the record levels achieved in 1981. A further decline is expected in the 1983 statistics. The sharpest decline in employment occurred in the electrical and petrochemical sectors, probably reflecting the completion of a number of large construction projects.

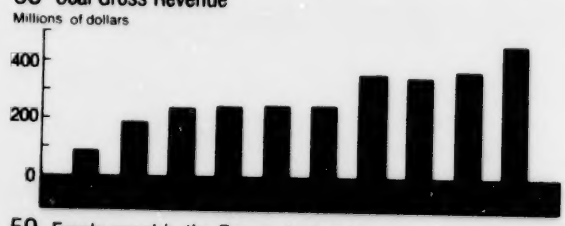
Investment statistics for gas and conventional crude oil, oil sands, and coal are shown in Chart 60. The decline in investment in 1982 was greater than the decline in employment, with reductions occurring in all but the coal sector.

57 Natural Gas Liquids Gross Revenue [1]

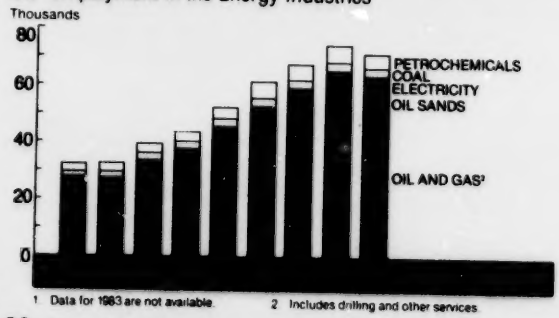



1 The values of ethane for 1974 through 1979 are not available.

58 Coal Gross Revenue

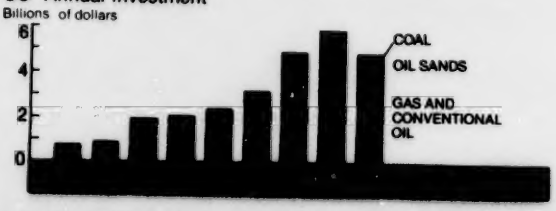



59 Employment in the Energy Industries




1 Data for 1983 are not available. 2 Includes drilling and other services.

60 Annual Investment



# Glossary

**Coal, Bituminous (Metallurgical)** - An agglomerating coal (sticks together and is therefore suitable for coke making) with a moist, mineral-matter-free, heating value of more than 26.7 megajoules per kilogram. It is mined in the *Mountain Region* and exported after cleaning.

**Coal, Bituminous (Thermal)** - A moist, mineral-matter-free coal, with a heating value of more than 26.7 megajoules per kilogram. It is usually non-agglomerating, but sometimes an agglomerating high-ash coal is used as a thermal coal. Most of the production is in the *Foothills Region* and is exported from the province after cleaning. High-ash thermal coal is burnt locally.

**Coal, Subbituminous** - A moist, non-agglomerating, mineral-matter-free coal, with a heating value of from 19.3 to 26.7 megajoules per kilogram. It is mined in the *Plains Region* and is used mainly (in as-mined condition) as a fuel for mine site electricity generating stations. Some is also used for domestic purposes.

**Coal, Clean** - Coal processed to meet user requirements of purity and uniformity.

**Coal, Raw** - Unprocessed coal as loaded in the mine. Also known as run-of-mine coal (R.O.M.).

**Crude Bitumen** - A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentanes that may contain sulphur compounds and that, in its naturally occurring viscous state, will not flow to a well.

**Crude Oil, Conventional** - A mixture of hydrocarbons that is recoverable from an underground reservoir through a well without special assistance such as by the application of heat.

**Crude Oil, Synthetic** - A mixture of hydrocarbons similar to conventional crude oil, that is derived from crude bitumen.

**Design Capacity** - The maximum rate at which a facility may be operated on a regular basis.

**Development Well** - A well drilled within, or close to, the limits of a producing or producible pool.

**Distribution Lines (Electric)** - Electric lines operating at 60 kilovolts or less, which distribute electricity from the transmission system to the end-use consumers.

**Drilling Mud** - Fluid circulated through a wellbore, during drilling and workover operations, to maintain control of the well and remove drill cuttings and other material from the wellbore.

**Electrical Generating Capacity** - Total installed capacity of electrical generating equipment.

**Established Reserves** - Those reserves recoverable, with reasonable certainty, under current technology and present and anticipated economic conditions.

**Exploratory Well** - A well drilled in an effort to find undiscovered resources.

**Flow Line** - A pipe (usually buried) through which fluids travel from a well to processing equipment, to storage, or to a central delivery point.

**Fly Ash** - Those particles of ash that are carried out of a furnace by the exhaust gas stream during the burning of coal.

**Fracturing Water** - Water, under high pressure, used to open cracks in a formation to stimulate production or injection.

**Gas Cap** - Free gas overlying an oil zone within the same reservoir.

**Heavy Oil** - Oil with a density of 900 kilograms per cubic metre or greater (API gravity of 25 degrees or less).

**In Situ Operations (Oil Sands)** - A scheme for the recovery of crude oil or crude bitumen usually involving the heating of it in the reservoir and producing it through wells.

**Initial Volume in Place** - The gross volume of crude oil, crude bitumen, raw natural gas, or coal calculated or interpreted to exist in a reservoir or deposit before production.

**Nitrogen Oxide** - A gaseous compound containing nitrogen and oxygen usually emitted by internal combustion equipment.

**Oil Sands** - The deposits of sand containing bitumen in northern Alberta.

**Oil Sands Scheme** - An approved scheme for the recovery of oil sands or crude bitumen.

**Pentanes Plus** - The heaviest portion of the natural gas liquids removed in the processing of raw gas.

**Petrochemical** - A chemical manufactured from petroleum or natural gas, or from raw materials derived from petroleum or natural gas.

**Price, Plant Gate** - The price after processing.

**Price, Wellhead** - The price of oil or gas at the facility where it is first recovered.

**Primary Energy Source** - An energy resource which is supplied in its raw form.

**Process Water** - Water used in an industrial operation.

**Recovery, Enhanced** - Recovery of a resource where the natural energy is supplemented.

**Recovery, Primary** - Recovery of a resource by natural energy or drive mechanisms.

**Recovery, Tertiary** - Recovery of a resource where additional energy is employed after an enhanced-recovery scheme has been applied, or where complex means are employed after primary recovery or at any time.

**Remaining Established Reserves** - Established reserves less cumulative production (see Established Reserves).

**Reservoir** - An underground, porous, permeable rock zone containing oil or gas, or both.

**Stock Tank Barrel** - A barrel of liquid measured at standard conditions of temperature and pressure (such as oil after the gas dissolved in it at underground reservoir conditions has been removed).

**Sulphur Dioxide** - A toxic gaseous compound containing sulphur and oxygen.

**Thermal Power** - Electricity which has been produced using hydrocarbon energy resources, such as coal or gas.

**Transmission Line** - An electric line operating at 60 kilovolts and greater which transmits electricity from generating stations to distribution systems.

**Ultimate Potential** - Established reserves, plus additions expected to existing pools, plus future discoveries expected.

**Waterflood** - Enhanced recovery of oil by injection of water.

# Units of Measurement

**Imperial Equivalent Units**

| | |
|---|---|
| 1 cubic metre of oil and pentanes plus (101.325 kilopascals and 15° Celsius) | = 6.292 9 Canadian barrels (35 imperial gallons) |
| 1 cubic metre of natural gas (101.325 kilopascals and 15° Celsius) | = 35.493 73 cubic feet (14.65 psia and 60° Fahrenheit) |
| 1 cubic metre of ethane (liquid) (equilibrium pressure and 15° Celsius) | = 6.330 Canadian barrels of ethane (liquid) (equilibrium pressure and 60° Fahrenheit) |
| | = 9.984 thousand cubic feet of ethane gas (14.65 psia and 60° Fahrenheit) |
| 1 cubic metre of butanes (liquid) (equilibrium pressure and 15° Celsius) | = 6.296 8 Canadian barrels of butanes (equilibrium pressure and 60° Fahrenheit) |
| 1 cubic metre of propane (liquid) (equilibrium pressure and 15° Celsius) | = 6.300 Canadian barrels of propane (equilibrium pressure and 60° Fahrenheit) |
| 1 cubic metre of water (equilibrium pressure and 15° Celsius) | = 6.290 Canadian barrels of water (equilibrium pressure and 60° Fahrenheit) |
| 1 cubic metre of ethane (gas) | = 35.310 73 cubic feet of ethane |
| 1 tonne | = 1000 kilograms |
| | = 1.102 311 short tons (2000 pounds) |
| | = 0.984 206 4 long tons (2240 pounds) |
| 1 kilojoule | = 0.948 213 3 British thermal units (Btu) |
| 1 metre | = 3.281 feet |
| 1 kilometre | = 0.621 miles |
| 1 hectare | = 2.471 acres |

**Metric Prefixes**

| Prefix | Multiple | Symbol | Term | Multiple | Symbol |
|---|---|---|---|---|---|
| kilo- | $10^3$ | k | million | $10^6$ | mm |
| mega- | $10^6$ | M | billion | $10^9$ | b |
| giga- | $10^9$ | G | trillion | $10^{12}$ | t |
| tera- | $10^{12}$ | T | quadrillion | $10^{15}$ | q |
| peta- | $10^{15}$ | P | | | |
| exa- | $10^{18}$ | E | | | |

# ERCB Senior Management – 31 December 1983

**Board Members**

| | |
|---|---|
| V. Millard | Chairman |
| G. J. DeSorcy | Vice Chairman |
| V. E. Bohme | |
| C. J. Goodman | |
| N. Strom | |

**Senior Advisors**

| | |
|---|---|
| G. A. Warne | Technical Assistant to the Board |
| E. J. Morin | Manager of Special Projects |

| **Managers** | **Departments** |
|---|---|
| K. W. Fuller | Administrative and Financial Services |
| R. G. Paterson | Coal |
| H. Antonio | Data Processing |
| L. A. Bellows | Development |
| F. J. Mink | Economics |
| R. F. Braun | Employee Relations |
| E. R. Brushett | Environment Protection |
| H. J. Webber | Gas |
| J. R. Pow | Geology |
| T. F. Homeniuk | Hydro and Electric |
| M. J. Bruni | Legal |
| J. A. Bray | Oil |
| R. G. Evans | Oil Sands |
| E. G. Fox | Pipeline |

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POOR

QUALITY

ORIGINAL